A Report of the Electric Power Survey Committee of the EDISON ELECTRIC INSTITUTE

A 4700-2 U 10/84

1983 ELECTRIC POWER ANNUAL REPORT

HISTORY: 1979-83 □ PROJECTIONS: 1984-93

FEATURES OF THE NEW REPORT

- This 1983 Electric Power Annual Report replaces and combines the features of what would have been the 1983 Year-End Electric Power Survey and the 1984 Annual Electric Power Survey. Historical and projected data for capability, peak load, and energy requirements have been placed in separate sections.

- The data in this report cover only the contiguous U.S. portions of NERC, i.e., the lower forty-eight states. The electric utility power systems of the United States are normally operated as three separate interconnected areas: the Eastern Interconnection, the Electric Reliability Council of Texas (ERCOT), and the Western Systems Coordinating Council (WSCC). Generating capacity available in one of these areas is not usually available to any other area. Also, generating capacity in one of the interconnected areas may not be available to serve load throughout that area due to various internal constraints.

- Regional and national values in this report do not include the capabilities, peak loads, or energy requirements of isolated electric power installations either serving local areas or owned by industries or institutions.

- This report institutes a new percent margin definition that divides the difference between the capability and peak load by the capability. This new calculation has been designated "Percent Capacity Margin" and differs from the "Percent Capability Margins" published in previous Electric Power Survey reports – values that had been derived by dividing the difference between the capability and peak load by the peak load (also often referred to as "Percent Reserve Margin").

- In conformity with NERC's new practice, projected peak load values are no longer reduced by the amount of interruptible contracts.

A REPORT OF THE ELECTRIC POWER SURVEY COMMITTEE OF THE EDISON ELECTRIC INSTITUTE

CONTRIBUTORS TO THE 1983 ELECTRIC POWER ANNUAL REPORT

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W. Wood, Public Service Electric & Gas Company
T. R. Daugherty, Edison Electric Institute, Secretary
C.S. Tobie, Edison Electric Institute, Editor

POWER SYSTEM AND AREA REPRESENTATIVES

O. L. Carter, Central & South West Services
W. F. Y. Chong, Hawaiian Electric Co., Inc.
C. Crawford, Tennessee Valley Authority
D. E. Eyre, Western Systems Coordinating Council
R. H. Gloff, Mid-America Interpool Newtwork
B. C. Hulsey, Southwest Power Pool
R. V. Knudsen, Midcontinent Area Power Pool
W. A. Lewis, East Central Area Reliability Coordination Agreement
J. N. Maughn, Southern Company Services, Inc.
C L. McNeese, Electric Reliability Council of Texas

MANUFACTURING COMPANIES CONTRIBUTING INFORMATION

Domestic

Allis-Chalmers Co.
ASEA Electric
Babcock & Wilcox Co.
Brown-Boveri Turbomachinery, Inc.
Combustion Engineering, Inc.
Cooper Energy Services
Elliott Company Div. United Technologies
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Figure 1/U.S. REGIONS OF THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

IDENTIFICATION OF RELIABILITY COUNCILS:

ECAR—East Central Area Reliability Coordination Agreement
ERCOT—Electric Reliability Council of Texas
MAAC—Mid-Atlantic Area Council
MAIN—Mid-America Interpool Network
MAPP—Mid-continent Area Power Pool
NPCC—Northeast Power Coordinating Council
SERC—Southeastern Electric Reliability Council
SPP—Southwest Power Pool
WSCC—Western Systems Coordinating Council

The electric utility systems of the United States are normally operated as three separate interconnected areas: the Eastern Interconnection, the Electric Reliability Council of Texas (ERCOT), and the Western Systems Coordinating Council (WSCC). Generating capacity available in one of these areas is not usually available to any other area. Also, generating capacity in one of the interconnected areas may not be available to serve load throughout that area due to various internal constraints.

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FOREWORD

This report replaces and combines the features of what would have been the 1983 Year-End and the 1984 Annual Electric Power Surveys. It presents information concerning the electric power supply, expansion of electric generating facilities, and the manufacture of heavy electric power equipment in the United States as of the end of 1983.

The reorganized report is divided into three parts. Part I covers the history of electric power supply from 1979 through 1983. Part II pertains to projected power supply values from 1984 through 1993. Part III has to do with the planned domestic manufacture and importation of heavy electric power equipment as of January 1, 1984.

The historical data from 1979 through 1983 are an accurate presentation of the peak load, capability installed to meet load, and energy requirements for these time periods. The electric power supply data shown in Parts I and II of this report are derived partly from EP-411 reports for previous years submitted to the Department of Energy, and from reports of the North American Electric Reliability Council (NERC). Historical capability values have all been revised to agree with installed capability figures provided to NERC headquarters by the reliability councils. Forecast values used herein are those compiled and validated by NERC and published in their report, ELECTRIC POWER SUPPLY AND DEMAND 1984-1993. Installed capability, peak load and percent capacity margin values shown in this report for the summer of 1983 update the preliminary actual values published in EEI's 1983 Post-Summer Electric Power Survey. In conformity with NERC's new practice, projected peak load values are no longer reduced by the amount of interruptible contracts.

Until three years ago, Annual Electric Power Survey power supply figures had been obtained by means of questionnaires sent to the regional and subregional utility reporting entities by the Edison Electric Institute on behalf of the Electric Power Survey Committee. When the switch in data source was made in 1981, consistent NERC-published values were included back to 1979. For a discussion of the magnitude of the break between the old EEI-collected series (pre-1979) and the NERC-collected series now reformatted for publication in these annual reports, see the FOREWORD in the 1981 Annual Electric Power Survey.

Data in this report represent the total electric utility industry of the contiguous United States, including Investor-Owned systems and those of governmental agencies – Federal, Municipal and State & Local – and also Rural Electric Cooperatives.

The reported data include some industrial power installations whose operations are coordinated with the utility systems with which they are interconnected and which thereby contribute to the public supply. The data do not include any isolated industrial or institutional power installations.

Data pertaining to power system capabilities, peak loads, percent capacity margins, and energy requirements are presented for each of the nine reliability councils of NERC. Boundaries of the nine reliability councils are shown by the map in Fig. 1. The North American Electric Reliability Council encompasses essentially all utility systems in the United States and five Canadian provinces, but the data presented in this report cover only the systems in the contiguous United States.

Part III of this report presents the results of the semi-annual survey on the manufacture and scheduling of heavy electric power equipment made as of January 1, 1984, by the Electric Power Survey Committee of the Edison Electric Institute in cooperation with representatives of the electric utility industry throughout the contiguous United States, with the nation's principal manufacturers of heavy electric power equipment, and with those foreign manufacturers supplying electric generating equipment to U.S. electric power systems.

The Electric Power Survey Committee is the only group servicing the electric utility and allied industries that conducts surveys on the manufacture and scheduling of heavy electric power equipment on a semi-annual basis. These surveys are also unique in that information on each planned project is cross checked with both the manufacturer and the system ordering the equipment. Furthermore, the time frame for ordered and scheduled units is not limited to ten years, but extends into the future as far out as equipment is officially ordered and scheduled for installation. The resulting data file also allows the semi-annual tracking of unit slippages and cancellations.

Projections presented in this report are based on the best information available from the turn of the year through the end of the first quarter of 1984. There could, however, be delays in the installation of scheduled capacity and reductions in the percent capacity margins. This may occur, for example, due to the inability of utilities to secure the financing or the regulatory approvals necessary to sustain the construction of new generating capacity. It is essential that the installation of both nuclear and coal-fired generating units proceed as currently scheduled and that conservation and load management programs be pursued at the same time to assure an adequate bulk electric power supply into the 1990s.

Definitions of the terms used in this report, together with information concerning methods of summarizing the data, appear on the following page.

DEFINITIONS AND METHODS OF SUMMARIZATION

INSTALLED CAPABILITY is the maximum load which a generating unit or a group of units can carry under specified conditions for a given period of time. Installed capability values are shown in the historical summer and winter tables.

CAPABILITY, as projected in this report, is equivalent to Planned Resources, defined by the North American Electric Reliability Council to include the total installed generating capacity which is existing, presently under construction, or in various stages of planning; plus scheduled capacity purchases, less scheduled capacity sales; less total generating capacity out of service in deactivated shutdown status. This capability must provide for the projected load plus scheduled maintenance, forced outages, system operating requirements, and any unforeseen load. The capabilities of all systems normally interconnected are based upon fully coordinated operation. Peak capability refers to the maximum capability, as defined above, at the approximate time and for the duration of the load referred to; that is, at the time of the summer peak load or the winter peak load. Regional capability, as reported herein, is the sum of the capabilities of the systems serving the region.

PEAK LOAD for a region may be either coincident or non-coincident. It is the sum of the actual or projected peak load of the electric utilities and any self-generating industrial facilities.

HISTORICAL AND PROJECTED INSTALLED MARGIN shown on the summer and winter tables represents the difference between Installed Capability and peak load. It is the margin available to replace generating equipment out of service due to planned scheduled maintenance, forced outages, and equipment deratings due to various causes. In addition, Installed Margin must provide an Operating Reserve to cover variations in peak load, and to regulate frequency and control transmission tie-line schedules.

CAVEATS: It is well to keep in mind that maximum regional loads do not occur in all cases in summer – in some cases they occur during the winter season. Looking at the installed margin for the country as a whole in summer does not give a valid picture of the electric power situation at that time, nor does it reflect the fact that maximum regional loads in some cases may occur in winter.

It is also true that regional installed capacity margins [and hence the installed margin for the sum of the regions] in summer or winter have not always represented the minimum or the maximum margin. The extremes of installed capacity margins may be influenced, for example, by the date of bringing new large generating facilities into commercial operation in relation to the time of the annual peak loads – the addition of a very large generating unit just before the peak could give a larger margin during the peak period than that which existed before the time of peak. Also, in areas having high proportions of hydroelectric generating capacity, the lowest margins may occur at times other than when the load is at a maximum because of low capability resulting from minimum water for power generation.

A good example of the full utilization of installed capacity margin occurred during the week of January 10-17, 1977, when the seven interconnected NERC regions east of the Rocky Mountains experienced a severe cold wave and unusually high peak loads. Although the records show a capacity margin of 31.5 percent for the winter of 1976/77 it was nevertheless necessary during that January week to implement emergency actions because of insufficient generating capability to supply the load. These actions included system-wide voltage reductions, interruption of interruptible loads, public appeals, and in some areas forced interruption of customer load. The shortage of generation occurred because approximately 20 percent of the generating capability was forced out of service due to frozen coal piles and equipment, blockage of water intakes due to ice, and frozen power plant control lines. This occurred in addition to about 10 percent of capacity being out of service for normal planned maintenance. During certain periods on January 17 it was impossible to maintain normal turbine speed because the load exceeded generation. The frequency, normally 60 cycles per second, dropped as low as 59.83 cycles per second before equilibrium was reached.

Electric Power Survey data shows an aggregate total installed capability for the seven NERC regions of 373,491 megawatts for the winter of 1976/77. The arithmetic sum of the regional peak loads was 261,156 megawatts. The simultaneous peak load on January 17 was very close to this figure.

PERCENT CAPACITY MARGIN is the installed margin divided by capability multiplied by 100.

LOAD FACTOR is the ratio of the megawatthour output supplied during a designated period to the output that would have occurred had the peak experienced during the period been constant throughout the period. For example, Annual Percent Load Factor is calculated by multiplying annual megawatthour requirements by 100 and dividing by the product of the annual peak load and the number of hours in a year (8,760 in normal years, 8,784 in leap years).

TOTAL U.S., as used in this publication, is equivalent to the lower forty-eight contiguous states; Alaska and Hawaii are omitted.

AVERAGE ANNUAL COMPOUND GROWTH RATES are calculated on a point-to-point basis, either by taking the fourth root of the difference between the values for the first and fifth historical years in Tables 1, 2, and 4, or the ninth root of the difference between the first and tenth projected years in Tables 10, 11, and 13.

CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

INDUSTRY PERFORMANCE IN 1983

During the year 1983, the electric power systems of the contiguous United States placed 10.0 thousand megawatts of additional electric generating capacity into commercial operation. This includes all units of 4 megawatts capacity and larger. Of this total, 22 units with capability ratings aggregating 728 megawatts are hydraulic, and 23 units totaling 9.1 thousand megawatts are thermal. Three of the thermal units were powered by nuclear fuel. Fifteen were conventional steam turbine-generators, 4 were combustion turbine-generators, and one was a diesel engine-generator. The individual generating units that make up the 10.0 thousand megawatts added during 1983 are identified in the actual additions listing on page 15.

This newly added capacity contributed to the increase in the total capability, or load-carrying ability, of the U.S. electric power systems to 611.6 thousand megawatts at the year end – an increase of 2.5 percent over the total at the end of 1982.

Of the total capability of 611.6 thousand megawatts, approximately 87 percent is thermal and the rest hydraulic. During the past five years, the total capability of the country's electric power systems has increased at an average annual rate of 2.5 percent.

The combined 1983 summer peak load, shown in Table 1 of this report, was 447.5 thousand megawatts or 8.9 percent higher than the 1983/84 winter peak load. This is the twentieth consecutive year during which the combined summer peak load exceeded the peak of the following winter. The point-to-point compound average annual increase between the 1979 and 1983 summer peak loads was 2.9 percent.

Table 2 shows that the combined winter 1983/84 peak load of the contiguous United States was 410.8 thousand megawatts – 10.0 percent higher than the winter 1982/83 peak load. The change in peak load during the past five years, from winter 1979/80, was a net increase of 41.9 thousand megawatts, and is equivalent to an average annual increase of 2.7 percent on a point-to-point compounded basis.

As can be seen from Table 4, during 1983 the energy requirements for the contiguous United States amounted to 2.3 billion megawatthours – 3.7 percent higher than the output for 1982. The point-to-point compound average annual increase between 1979 and 1983 for energy requirements was 1.0 percent.

The 1983 annual load factor for the sum of the nine regions was 59.7 percent.

Table 1/SUMMER INSTALLED CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS (Megawatts)

Regions		1979	1980	1981	1982	1983	83/82 % Inc	Growth Rate 1979-1983*
NPCC	Installed Capability	50,510	51,069	50,504	50,563	50,508	-0.1%	0%
	Peak Load	34,673	36,831	35,640	36,427	37,627	3.3%	2.1%
	Installed Margin	15,837	14,238	14,864	14,136	12,881		
	% Capacity Margin	31.4%	27.9%	29.4%	28.0%	25.5%		
MAAC	Installed Capability	44,928	45,008	45,109	46,461	46,734	0.6%	1.0%
	Peak Load	31,780	34,525	33,633	33,846	34,783	2.8%	2.3%
	Installed Margin	13,148	10,483	11,476	12,615	11,951		
	% Capacity Margin	29.3%	23.3%	25.4%	27.2%	25.6%		
ECAR	Installed Capability	87,326	88,222	89,495	89,919	90,914	1.1%	1.0%
	Peak Load	61,716	63,021	64,150	59,668	65,959	10.5%	1.7%
	Installed Margin	25,610	25,201	25,345	30,251	24,955		
	% Capacity Margin	29.3%	28.6%	28.3%	33.6%	27.4%		
SERC	Installed Capability	109,898	111,315	117,293	121,533	124,999	2.9%	3.3%
	Peak Load	83,209	89,815	90,513	86,229	97,235	12.8%	4.0%
	Installed Margin	26,689	21,500	26,780	35,304	27,764		
	% Capacity Margin	24.3%	19.3%	22.8%	29.0%	22.2%		
MAIN	Installed Capability	43,273	41,706	40,795	40,578	40,797	0.5%	-1.5%
	Peak Load	33,751	33,894	32,561	31,394	34,704	10.5%	0.7%
	Installed Margin	9,522	7,812	8,234	9,184	6,093		
	% Capacity Margin	22.0%	18.7%	20.2%	22.6%	14.9%		
SPP	Installed Capability	45,925	50,576	54,215	58,236	59,294	1.8%	6.6%
	Peak Load	37,607	44,981	44,623	43,064	45,881	6.5%	5.1%
	Installed Margin	8,318	5,595	9,592	15,172	13,413		
	% Capacity Margin	18.1%	11.1%	17.7%	26.1%	22.6%		
ERCOT	Installed Capability	40,765	42,486	43,045	43,452	43,800	0.8%	1.8%
	Peak Load	27,828	31,722	32,535	33,231	34,972	5.2%	5.9%
	Installed Margin	12,937	10,764	10,510	10,221	8,828		
	% Capacity Margin	31.7%	25.3%	24.4%	23.5%	20.2%		
MAPP	Installed Capability	24,316	25,598	27,371	27,331	27,952	2.3%	3.5%
	Peak Load	18,132	19,378	18,985	19,470	20,785	6.8%	3.5%
	Installed Margin	6,184	6,220	8,386	7,861	7,167		
	% Capacity Margin	25.4%	24.3%	30.6%	28.8%	25.6%		
WSCC	Installed Capability	97,565	102,257	104,392	108,069	111,451	3.3%	3.4%
	Peak Load	69,728	72,891	75,655	71,580	75,580	5.6%	2.0%
	Installed Margin	27,837	29,366	28,737	36,489	36,058		
	% Capacity Margin	28.5%	28.7%	27.5%	33.8%	32.3%		
TOTAL UNITED STATES**	Installed Capability	544,506	558,237	572,219	586,142	596,449	1.8%	2.3%
	Peak Load	398,424	427,058	428,295	414,909	447,526	7.9%	2.9%
	Installed Margin	146,082	131,179	143,924	171,233	149,110		
	% Capacity Margin	26.8%	23.5%	25.2%	29.2%	25.0%		

*Compound annual growth rate from 1979 to 1983

**U.S. totals are meaningless and should not be used for policy purposes

NOTE: For definitions of terms see page 5

Table 2/WINTER INSTALLED CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS (Megawatts)

Regions		1979/80	1980/81	1981/82	1982/83	1983/84	83/82 % Inc	Growth Rate 1979-1983*
NPCC	Installed Capability	52,781	52,986	53,060	52,289	52,018	0.5%	0.4%
	Peak Load	34,552	35,340	35,199	34,755	35,836	3.1%	0.9%
	Installed Margin	18,229	17,646	17,861	17,534	16,182		
	% Capacity Margin	34.5%	33.3%	33.7%	33.5%	31.1%		
MAAC	Installed Capability	46,789	47,638	46,567	48,330	49,283	2.0%	1.3%
	Peak Load	27,858	29,730	30,726	28,197	30,150	6.9%	2.0%
	Installed Margin	18,931	17,908	15,841	20,133	19,133		
	% Capacity Margin	40.5%	37.6%	34.0%	41.7%	38.8%		
ECAR	Installed Capability	88,369	89,836	91,731	91,045	91,642	0.7%	0.9%
	Peak Load	59,560	62,225	63,188	56,559	63,820	12.8%	1.7%
	Installed Margin	28,809	27,611	28,543	34,486	27,822		
	% Capacity Margin	32.6%	30.7%	31.1%	37.9%	30.4%		
SERC	Installed Capability	113,566	116,472	122,379	125,575	129,941	3.5%	3.4%
	Peak Load	82,612	90,354	93,348	85,664	91,459	6.8%	2.6%
	Installed Margin	30,954	26,118	29,031	39,911	38,482		
	% Capacity Margin	27.3%	22.4%	23.7%	31.8%	29.6%		
MAIN	Installed Capability	44,456	42,212	41,596	42,082	44,132	4.9%	0.2%
	Peak Load	27,449	26,631	26,965	24,303	28,159	15.9%	0.6%
	Installed Margin	17,007	15,581	14,631	17,779	15,973		
	% Capacity Margin	38.3%	36.9%	35.2%	42.2%	36.2%		
SPP	Installed Capability	46,754	51,186	54,004	56,960	59,571	4.6%	6.2%
	Peak Load	28,289	30,681	32,087	32,743	35,799	9.3%	6.1%
	Installed Margin	18,465	20,505	21,917	24,217	23,772		
	% Capacity Margin	39.5%	40.1%	40.6%	42.5%	39.9%		
ERCOT	Installed Capability	38,116	42,248	40,627	43,451	43,943	1.1%	3.6%
	Peak Load	21,444	23,962	25,393	25,347	29,684	17.1%	8.5%
	Installed Margin	16,672	18,286	15,234	18,104	14,259		
	% Capacity Margin	43.7%	43.3%	37.5%	41.7%	32.4%		
MAPP	Installed Capability	25,224	26,541	28,651	28,652	29,088	1.5%	3.6%
	Peak Load	17,269	17,420	17,508	17,816	18,807	5.6%	2.2%
	Installed Margin	7,955	9,121	11,143	10,836	10,281		
	% Capacity Margin	31.5%	34.4%	38.9%	37.8%	35.3%		
WSCC	Installed Capability	98,470	103,076	102,469	108,546	112,019	3.2%	3.3%
	Peak Load	69,843	68,224	66,692	67,934	77,065	13.4%	2.5%
	Installed Margin	28,627	34,852	35,777	40,612	34,954		
	% Capacity Margin	29.1%	33.8%	34.9%	37.4%	31.2%		
TOTAL UNITED STATES**	Installed Capability	554,525	572,195	581,084	596,930	611,637	2.5%	2.5%
	Peak Load	368,876	384,567	391,106	373,318	410,779	10.0%	2.7%
	Installed Margin	185,649	187,628	189,978	223,612	200,858		
	% Capacity Margin	33.5%	32.8%	32.7%	37.5%	32.8%		

*Compound annual growth rate from 1979/80 to 1983/84

**U.S. totals are meaningless and should not be used for policy purposes

NOTE: For definitions of terms see page 5

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS/1979-1983

The relationship between the summer and winter peak loads in the different regions of the country, and also for the contiguous United States, are shown in the accompanying table, where the summer peak load in each case is expressed as a percentage of the winter peak load for the following season.

In those regions where the summer peak load has been characteristically higher than the peak during the following winter, the percentage figure has, expectedly, been above 100 percent. This has been true particularly in SPP and ERCOT, where, due to climatic conditions, heavy air conditioning loads during the summer months have caused peaks that far exceed those during the following winter.

Since the mid-1960s, summer peaks for the country as a whole have generally exceeded the peaks for the following winter by increasing amounts. In 1970, and again in 1971, apparently normal summer peaks were followed by winter peaks depressed both by mild weather and reduced industrial loads. This combination produced summer to winter peak relationships of 111 percent and 112 percent respectively in 1970 and 1971.

After falling back to 110 percent in 1972, the summer/winter ratio jumped to an all-time high of 117 percent in 1973 because of the unprecedented drop in the winter peak load from the year previous. The ratio lowered only one point in 1974 since both the summer and winter peak loads were little changed from those experienced in 1973. Through the rest of the 1970s the ratio fluctuated in the more normal range of between 106 and 108 percent. The hot summer of 1980 and the economic downturn of 1981 helped to produce values of 111 and 110 percent respectively. In 1982 the summer peak dropped 3.1 percent and winter peak dropped 4.5 percent. The greater relative decline in the winter peak caused the summer/winter ratio to increase to 111 in 1982. In 1983, offsetting changes in the nine regions held the national ratio at 111 percent.

Table 3/SUMMER PEAK LOADS EXPRESSED AS PERCENTAGE OF PEAK LOAD FOR THE FOLLOWING WINTER

Regions	1968	1969	1970	1971	1972	73/74	74/75	75/76	76/77	77/78	78/79	79/80	80/81	81/82	82/83	83/84
NPCC	96	99	96	101	98	111	104	102	96	105	102	100	104	101	105	107
MAAC	114	114	114	118	118	133	123	114	108	115	111	114	116	109	120	115
ECAR	101	100	102	107	103	112	105	102	97	101	99	104	101	102	105	103
SERC	102	105	111	109	108	106	109	100	93	99	99	101	99	97	101	105
MAIN	121	120	120	125	121	133	125	119	122	122	118	123	127	121	129	127
SPP	139	147	155	146	149	143	156	124	144	144	138	133	147	139	132	133
ERCOT	150	160	153	149	146	149	157	141	142	142	134	130	132	128	131	131
MAPP	108	109	110	112	110	125	119	106	103	103	111	105	111	108	109	114
WSCC	87	97	97	97	96	104	107	104	107	107	98	100	107	113	105	101
U.S. TOTAL	105	109	111	112	110	117	116	108	106	106	107	108	111	110	111	111

The 1983 energy requirements and annual load factors by reliability council are given in Tables 4 and 5, together with corresponding information for the previous four years.

Table 4 shows that during 1983 electric energy requirements for the contiguous United States amounted to 2.3 billion megawatthours – 3.7 percent higher than the output for 1982. The point-to-point compound average annual increase between 1979 and 1983 for energy requirements was 1.0 percent.

As can be seen from Table 5, the 1983 annual load factor for the sum of the nine regions declined to 59.7 percent. This dip below the usual value in the low 60's of percent is largely a function of the fact that the summer peak increased more than twice as much as energy output in 1983.

Table 4/ANNUAL ENERGY REQUIREMENTS (Megawatthours in Thousands)

Regions	1979	1980	1981	1982	1983	83/82 % Inc	Growth Rate 1979-1983*
NPCC	201,708	203,954	202,620	201,377	210,815	4.7%	1.1%
MAAC	171,567	175,622	174,688	171,662	179,990	4.9%	1.2%
ECAR	379,018	366,198	366,376	347,091	364,501	5.0%	-1.0%
SERC	459,420	479,715	483,595	466,832	490,899	5.2%	1.7%
MAIN	171,052	166,116	162,899	158,116	165,974	5.0%	-0.8%
SPP	191,762	213,381	211,833	211,595	217,688	2.9%	3.2%
ERCOT	150,533	162,327	164,920	169,769	173,372	2.1%	3.6%
MAPP	96,518	96,422	96,307	96,992	102,526	5.7%	1.5%
WSCC	425,349	428,983	447,788	435,310	435,868	0.1%	0.6%
TOTAL U.S.	2,246,927	2,292,718	2,311,026	2,258,744	2,341,633	3.7%	1.0%

*Compound annual growth rate from 1979 to 1983

Table 5/ANNUAL LOAD FACTOR, %

Regions	1979	1980	1981	1982	1983
NPCC	66.4	63.0	64.9	63.1	64.0
MAAC	61.6	57.9	59.3	57.9	59.1
ECAR	70.1	66.2	65.2	66.4	63.1
SERC	63.0	60.4	59.1	61.8	57.6
MAIN	57.9	55.8	57.4	57.5	54.6
SPP	58.2	54.0	54.2	56.1	54.2
ERCOT	61.8	58.3	57.9	58.3	56.6
MAPP	60.8	56.6	57.9	56.9	56.3
WSCC	69.5	67.0	67.6	69.4	65.8
TOTAL U.S.	64.4	61.1	61.6	62.1	59.7

Table 6A/CHANGES IN SCHEDULED OPERATION DATE OF NUCLEAR AND FOSSIL-FIRED STEAM TURBINE-GENERATORS, 300 mW OR LARGER, REMOVED FROM SCHEDULE BETWEEN JANUARY 1, 1983 AND JANUARY 1, 1984

Owner	Unit Name & Number		Net Expected Capability mW	Scheduled Operation Date as of Jan. 1, 1983	Scheduled Operation Date as of Jan. 1, 1984
Nuclear Removals					
Carolina Power & Light Company	Shearon Harris No. 2		900	3-90	Removed
Cincinnati Gas & Electric Company	Zimmer No. 1		800	12-83	Removed
Consumers Power Company	Midland No. 1		530	7-84	Removed
Project Management Corp.	Clinch River Breeder		350	4-90	Removed
Puget Sound Power & Light Company	Skagit No. 1		1,288	1-91	Removed
Puget Sound Power & Light Company	Skagit No. 2		1,288	1-93	Removed
	Total Nuclear Units Removed from Schedule	6	5,156		
Fossil Removals					
Cajun Electric Power Coop.	Oxbox No. 1		512	5-88	Removed
Cajun Electric Power Coop.	Oxbox No. 2		512	5-94	Removed
Cincinnati Gas & Electric Company	East Bend No. 1		600	3-88	Removed
Los Angeles Dept. of Water & Power	Intermountain No. 3		750	7-88	Removed
Los Angeles Dept. of Water & Power	Intermountain No. 4		750	7-89	Removed
Louisville Gas & Electric Company	Trimble County No. 2		495	6-93	Removed
New York Power Authority	Arthur Kill		700	5-90	Removed
Pacific Power & Light Company	Wyodak No. 2		310	12-89	Removed
Soyland Power Cooperative	Soyland No. 1		450	5-87	Removed
Texland Electric Cooperative	Texas 156 No. 1		560	-87	Removed
Texland Electric Cooperative	Texas 156 No. 2		560	88	Removed
Texland Electric Cooperative	Texas 156 No. 3		560	89	Removed
	Total Fossil Units Removed from Schedule	12	6,759		

Table 6B/CHANGES IN SCHEDULED OPERATION DATE OF NUCLEAR AND FOSSIL-FIRED STEAM TURBINE-GENERATORS, 300 mW OR LARGER, DELAYED A YEAR OR MORE BETWEEN JANUARY 1, 1983 AND JANUARY 1, 1984

Owner	Unit Name & Number		Net Expected Capability mW	Scheduled Operation Date as of Jan. 1, 1983	Scheduled Operation Date as of Jan. 1, 1984
Nuclear Delays					
Cleveland Electric Illuminating Co	Perry No. 1		1,205	1-84	3-85
Consumers Power Company	Midland No. 2		805	12-83	7-86
Detroit Edison Company	Enrico Fermi No. 2		1,093	11-83	12-84
Illinois Power Company	Clinton No. 1		950	8-84	11-86
Long Island Lighting Company	Shoreham No. 1		809	1-84	7-85
Mississippi Power & Light Company	Grand Gulf No. 2		1,250	11-88	4-90
Pacific Gas & Electric Company	Diablo Canyon No. 1		1,086	5-83	6-84
Philadelphia Electric Company	Limerick No. 2		1,055	10-88	4-90
Public Service Co. of New Hampshire	Seabrook No. 1		1,150	12-84	8-86
Public Service Co. of New Hampshire	Seabrook No. 2		1,150	7-87	1-91
Tennessee Valley Authority	Bellefonte No. 1		1,212	11-86	4-89
Tennessee Valley Authority	Bellefonte No. 2		1,212	11-87	4-91
Washington Public Power Supply System	Nuclear Project No. 3		1,240	12-86	12-89
	Total Nuclear Units Delayed	13	14,217		
Fossil Delays					
Arizona Public Service Company	Cholla No. 5		340	6-91	6-93
Brazos Electric Power Coop.	San Miguel No. 2		400	6-89	1-91
Central Power & Light Company	Coleto Creek No. 2		700	11-88	12-90
General Public Utilities	Coal No. 2		625	12-94	5-97
Houston Lighting & Power Company	Malakoff No. 2		600	11-89	6-91
Iowa Electric Light & Power Company	Guthrie County No. 1		650	12-88	12-90
Louisiana Power & Light Company	Wilton No. 1		800	1-90	1-92
Louisiana Power & Light Company	Wilton No. 2		800	1-92	1-97
South Carolina Public Service Authority	Cross No. 1		450	5-88	5-91
Texas Utilities Company System	Twin Oak No. 1		750	11-87	2-89
Utah Power & Light Company	Hunter No. 4		400	6-88	6-91
	Total Fossil Units Delayed	11	6,515		

The 1983 additions to electric generating capability in the contiguous United States are shown in the top part of Table 7 according to the type of generating units. The second portion of the table presents the same information arranged according to the reliability councils in which the new capability was installed. The third portion of the table reports the same information classified according to ownership of the new units.

Table 7/1983 ADDITIONS TO ELECTRIC GENERATING CAPABILITY (In Terms of Net Expected Capabilities of the Units)

	THERMAL								HYDRAULIC					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine-Generators		Conventional		Pumped Storage		Total	
	Nuclear		Conventional											
	No. of Units	mW	No. of Units	mW	No. of Units	mW	No. of Units	mW	No. of Units	mW	No. of Units	mW	No. of Units	mW
1983 ADDITIONS	3	2,952	15	5,845	4	335	1	4	22	728			45	9,864
ADDITIONS BY REGION														
NPCC									5	42			5	42
MAAC	1	1,050											1	1,050
ECAR			1	344					1	20			2	364
SERC	1	802	2	1,220					4	197			7	2,319
MAIN			1	44									1	44
SPP			4	2,316	2	88	1	4					7	2,408
ERCOT			1	400					2	66			3	466
MAPP			2	800									2	800
WSCC	1	1,100	4	621	2	247			10	403			17	2,371
ADDITIONS BY OWNERSHIP														
Investor-Owned	3	2,952	8	3,766	2	247			10	340			23	7,305
Federal									7	296			7	296
Municipal			4	659	2	88	1	4	2	47			9	798
Cooperative			3	1,420									3	1,420
State and Local									3	45			3	45

Table 8/1983 ADDITIONS TO ELECTRIC GENERATING CAPABILITY
U.S. Electric Power Systems
Units 4,000 Kw and Larger

SYMBOLS

Investor-Owned	I
Federal	F
Municipal	M
Cooperative	C
State & Local	SL
Thermal	
Conventional steam turbine-generator	T
Nuclear steam turbine-generator	N
Combustion turbine-generator	G
Diesel engine-generator	D
Hydraulic	
Hydraulic turbine-generator	H
Pumped-Storate	
Pumped-storage turbine-generator	S
Reversible pumped-storage turbine-generator	R
Combined-Cycle	
Combustion turbine-generator for combined-cycle operation	GC
Conventional steam turbine-generator for combined-cycle operation	TC

+ Denotes multiple ownership of the unit. In such cases, the name of the participating power system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the power system shown is the first in alphabetical order among the major participants.

NOTES: Megawatts shown for individual generating units represent, in most cases, the net operating capability expected by the power systems; in other cases they represent the manufacturer's nameplate rating of the unit.

SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	mW of NET EXPECTED CAPABILITY
NPCC:					
NEW YORK STATE ELECTRIC & GAS CORP	UPPER MECHANICSVILLE NO 1	I	H		8
NEW YORK STATE ELECTRIC & GAS CORP	UPPER MECHANICSVILLE NO 2	I	H		8
NIAGARA MOHAWK POWER CORPORATION	GRANBY NO 1	I	H		5
NIAGARA MOHAWK POWER CORPORATION	GRANBY NO 2	I	H		5
NORTHEAST UTILITIES	HADLEY FALLS NO 2	I	H		15
MAAC:					
+PENNSYLVANIA POWER & LIGHT COMPANY	SUSQUEHANNA NO 1	I	N		1,050
ECAR:					
AMERICAN ELECTRIC POWER COMPANY	RACINE DAM A	I	H		20
NORTHERN INDIANA PUBLIC SERVICE CO	SCHAHFER NO 17	I	T	Coal	344
SERC:					
ALABAMA POWER COMPANY	HARRIS NO 1	I	H		59
ALABAMA POWER COMPANY	HARRIS NO 2	I	H		59
CAROLINA POWER & LIGHT COMPANY	MAYO NO 1	I	T	Coal	720
+FLORIDA POWER & LIGHT COMPANY	ST LUCIE NO 2	I	N		802
SEMINOLE ELECTRIC COOP	SEMINOLE NO 1	C	T	Coal	600
U S ARMY CORPS OF ENGINEERS	HARTWELL NO 5 (SOCO)	F	H		40
U S ARMY CORPS OF ENGINEERS	HARTWELL NO 5 (VACAR)	F	H		40
MAIN:					
MARQUETTE MICHIGAN	SHIRAS NO 3	M	T	Coal	44
SPP:					
ARKANSAS POWER & LIGHT COMPANY	INDEPENDENCE NO 1	I	T	Coal	816
+CAJUN ELECTRIC POWER COOP	BIG CAJUN TWO NO 3	C	T	Coal	540
HUGOTON KANSAS	MUNICIPAL POWER PLANT	M	D	Oil	4
+KANSAS POWER & LIGHT COMPANY	JEFFREY ELEC CENTER NO 3	I	T	Coal	680
SPRINGFIELD MISSOURI	SOUTHWEST NO 1	M	G		44
SPRINGFIELD MISSOURI	SOUTHWEST NO 2	M	G		44
SUNFLOWER ELECTRIC COOP	HOLCOMB NO 1	C	T	Coal	280

SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	mW of NET EXPECTED CAPABILITY
ERCOT:					
INTERNTNL WATER & BOUNDARY COMM	AMISTAD NO 1	F	H		33
INTERNTNL WATER & BOUNDARY COMM	AMISTAD NO 2	F	H		33
TEXAS MUNICIPAL POWER AGENCY	GIBBONS CREEK NO 1	M	T	Coal	400
MAPP:					
+IOWA-ILLINOIS GAS & ELECTRIC CO	LOUISA NO 1	I	T	Coal	650
MUSCATINE IOWA	MUSCATINE NO 9	M	T	Coal	150
WSCC:					
CALIFORNIA DEPT OF WATER RESOURCES	W E WARNE NO 2	SL	H		38
METROPOLITAN WATER DISTRICT	PERRIS NO 1	M	H		10
PACIFIC GAS & ELECTRIC COMPANY	GEYSERS NO 18	I	T	Geothermal	114
PACIFIC GAS & ELECTRIC COMPANY	KERCKHOFF NO 2	I	H		151
PUGET SOUND POWER & LIGHT COMPANY	FREDONIA NO 1	I	G		124
PUGET SOUND POWER & LIGHT COMPANY	FREDONIA NO 2	I	G		124
SOLANO IRRIGATION DISTRICT	MONTICELLO NOS 1 & 2	SL	H		7
+SOUTHERN CALIFORNIA EDISON COMPANY	SAN ONOFRE NO 2	I	N		1,100
TACOMA WASHINGTON	MAYFIELD NO 4	M	H		39
U S BUREAU OF RECLAMATION	GRAND COULEE PG-9	F	H		50
U S BUREAU OF RECLAMATION	GRAND COULEE PG-10	F	H		50
U S BUREAU OF RECLAMATION	GRAND COULEE PG-11	F	H		50
UTAH POWER & LIGHT COMPANY	HUNTER NO 3	I	T	Coal	400
WASHINGTON WATER POWER COMPANY	KETTLE FALLS	I	T	Wood	42
45 GENERATING UNITS WERE ADDED WITH TOTAL NET EXPECTED CAPABILITY OF					9,865 mW

NUCLEAR ELECTRIC POWER GENERATING UNITS IN COMMERCIAL OPERATION

No steam turbine-generators for nuclear projects have been ordered since 1976, and no nuclear steam supply systems (reactors) since 1978.

As of January 1, 1984, nuclear capacity accounts for 51 percent of the aggregate of the industry's scheduled expansion program.

Table 9 has been reformatted to show subtotals of the amount of nuclear megawatts placed in service each year. As of January 1, 1984, there were 77 nuclear units in commercial operation with an aggregate winter rating of 59.6 thousand megawatts. Two small nuclear units in the 60 megawatt class, Humboldt Bay and Shippingport No. 1, have been decommissioned and therefore no longer appear on the list. There were three additions to nuclear generating capacity during 1983.

NUCLEAR ELECTRIC POWER GENERATING UNITS IN COMMERCIAL OPERATION

Table 9/NUCLEAR POWER UNITS IN OPERATION IN THE CONTIGUOUS U.S. as of January 1, 1984

SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMMERCIAL OPERATION	CAPABILITY SUMMER MW	CAPABILITY WINTER MW	YEARLY SUBTOTALS OF SUMMER MW RATINGS
1 Commonwealth Edison Company	Dresden No. 1	1960	197	207	197
2 Yankee Atomic Electric Company	Yankee No. 1	1961	175	176	175
3 Consumers Power Company	Big Rock Point	1962	63	63	63
4 Washington Pub Pwr Sply Sys	Hanford	1966	840	840	840
5 Conn Yankee Atomic Power Co	Haddam No. 1	1968	555	580	
6 SoCal Edison & San Diego G &E	San Onofre No. 1	1968	436	436	991
7 GPU Nuclear Corporation	Oyster Creek No. 1	1969	620	650	
8 Niagara Mohawk Power Corp	Nine Mile Point No. 1	1969	610	610	
9 Rochester Gas & Electric Corp	Ginna No. 1	1969	470	470	1,700
10 Northeast Utilities	Millstone Point No. 1	1970	654	660	
11 Wisconsin Electric Power Co	Point Beach No. 1	1970	495	495	1,149
12 Carolina Power & Light Co	Robinson No. 2	1971	665	700	
13 Dairyland Power Cooperative	La Crosse	1971	46	46	
14 Northern States Power Supply	Monticello No. 1	1971	536	557	
15 Commonwealth Edison Company	Dresden No. 2	1971	772	794	2,019
16 Boston Edison Company	Pilgrim No. 1	1972	670	670	
17 Commonwealth Edison Company	Quad Cities No. 1	1972	768	789	
18 Commonwealth Edison Company	Quad Cities No. 2	1972	769	789	
19 Florida Power & Light Company	Turkey Point No. 3	1972	666	696	
20 Maine Yankee Atomic Power Co	Wiscasset	1972	814	830	
21 Vermont Yankee N. Power Corp	Vernon	1972	496	528	
22 Virginia Electric & Power Co	Surry No. 1	1972	775	775	4,958
23 Commonwealth Edison Company	Dresden No. 3	1973	773	794	
24 Consumers Power Company	Palisades No. 1	1973	635	740	
25 Duke Power Company	Oconee No. 1	1973	860	860	
26 Duke Power Company	Oconee No. 2	1973	860	860	
27 Florida Power & Light Company	Turkey Point No. 4	1973	666	696	
28 Northern States Power Company	Prairie Island No. 1	1973	503	523	
29 Omaha Public Power District	Fort Calhoun No. 1	1973	439	457	
30 Tennessee Valley Authority	Browns Ferry No. 1	1973	1,067	1,067	
31 Virginia Electric & Power Co	Surry No. 2	1973	775	775	

	SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMMERCIAL OPERATION	CAPABILITY SUMMER MW	CAPABILITY WINTER MW	YEARLY SUBTOTALS OF SUMMER MW RATINGS
32	Wisconsin Electric Power Co	Point Beach No. 2	1973	495	495	7,073
33	Arkansas Power & Light Co	Arkansas Nuclear No. 1	1974	836	836	
34	Commonwealth Edison Company	Zion No. 1	1974	1,040	1,040	
35	Commonwealth Edison Company	Zion No. 2	1974	1,040	1,040	
36	Consolidated Edison Co. of NY	Indian Point No. 2	1974	849	864	
37	Duke Power Company	Oconee No. 3	1974	860	860	
38	Iowa Electric Light & Power Co	Arnold No. 1	1974	480	510	
39	GPU Nuclear Corporation	Three Mile Island No. 1	1974	776	800	
40	Nebraska Public Power District	Cooper Nuclear No. 1	1974	778	778	
41	Northern States Power Company	Prairie Island No. 2	1974	500	520	
42	Philadelphia Electric Company	Peach Bottom No. 2	1974	1,051	1,055	
43	Philadelphia Electric Company	Peach Bottom No. 3	1974	1,035	1,035	
44	Wisconsin Public Service Corp	Kewaunee No. 1	1974	525	517	9,770
45	Baltimore Gas & Electric Co	Calvert Cliffs No. 1	1975	810	820	
46	Carolina Power & Light Company	Brunswick No. 2	1975	790	790	
47	Georgia Power Company	Hatch No. 1	1975	771	771	
48	Indiana & Michigan Electric Co	Cook No. 1	1975	1,050	1,050	
49	New York Power Authority	Fitzpatrick No. 1	1975	821	821	
50	Sacramento Utility District	Rancho Seco No. 1	1975	875	903	
51	Tennessee Valley Authority	Browns Ferry No. 2	1975	1,067	1,067	6,184
52	Duquesne Light Company	Beaver Valley No. 1	1976	800	800	
53	Florida Power & Light Company	St. Lucie No. 1	1976	777	795	
54	Northeast Utilities	Millstone Point No. 2	1976	864	864	
55	Portland General Electric Co	Trojan	1976	1,080	1,080	
56	New York Power Authority	Indian Point No. 3	1976	965	965	4,486
57	Alabama Power Company	Farley No. 1	1977	807	807	
58	Baltimore Gas & Electric Co	Calvert Cliffs No. 2	1977	825	860	
59	Carolina Power & Light Company	Brunswick No. 1	1977	790	790	
60	Florida Power Corporation	Crystal River No. 3	1977	782	807	
61	Public Service Elec & Gas Co	Salem Nuclear No. 1	1977	1,079	1,100	
62	Tennessee Valley Authority	Browns Ferry No. 3	1977	1,067	1,067	
63	Toledo Edison Company	Davis-Besse No. 1	1977	906	906	6,256
64	Indiana & Michigan Electric Co	Cook No. 2	1978	1,100	1,100	
65	Virginia Electric & Power Co	North Anna No. 1	1978	898	907	1,998
66	Georgia Power Company	Hatch No. 2	1979	771	771	
67	Public Service Co. of Colorado	Fort St. Vrain No. 1	1979	200	200	971
68	Arkansas Power & Light Co	Arkansas Nuclear No. 2	1980	858	858	
69	Virginia Electric & Power Co	North Anna No. 2	1980	870	870	1,728
70	Alabama Power Company	Farley No. 2	1981	812	812	
71	Duke Power Company	McGuire No. 1	1981	1,180	1,180	
72	Public Service Elec & Gas Co	Salem Nuclear No. 2	1981	1,106	1,120	
73	Tennessee Valley Authority	Sequoyah No. 1	1981	1,128	1,128	4,226
74	Tennessee Valley Authority	Sequoyah No. 2	1982	1,148	1,148	1,148
75	Florida Power & Light Company	St. Lucie No. 2	1983	802	802	
76	Pennsylvania Power & Light Co	Susquehanna No. 1	1983	1,050	1050	
77	SoCal Edison & San Diego G & E	San Onofre No. 2	1983	1,100	1,100	2,952
	77	Nuclear units totaling		58,884 SUMMER MW	59,592 WINTER MW	58,884

SUMMER CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

Summer peak capabilities, peak loads, and percent capacity margins as now forecast for the years 1984 through 1993 are shown in Table 1, page 21. Similar information for winter is shown in Table 2, page 23.

SUMMER CAPABILITIES

The summer capability values shown in this report are generally below the projections for the same years 12 months ago. For the nine regions taken together, reductions range from 0.5 to 2.8 percent for the years 1984 through 1992.

The 1993 summer capability for the sum of the nine regions is projected at 714.1 thousand megawatts. This represents an average annual increase of 1.8 percent between the first and tenth forecast years.

The total capability of the electric utility industry of the contiguous United States, given herein for summer 1984 (606.3 thousand megawatts) and projected to summer 1993 (714.1 thousand megawatts), consists of the following types of equipment in approximately the proportions listed below.

Summer Capabilities Mix	1984	1983
Coal-Fired Steam Turbine-Generators	43.6%	44.0%
Oil-Fired Steam Turbine-Generators	6.4	5.0
Gas-Fired Steam Turbine-Generators	6.3	4.9
Dual-Fired Steam Turbine-Generators	11.9	9.2
Nuclear Steam Turbine-Generators	10.7	16.3
Conventional Hydro Generators	10.4	9.4
Pumped-Storage Generators	2.4	2.6
Combustion Turbine-Generators	6.6	5.8
Combined-Cycle Generators	1.0	0.9
Geothermal Turbine-Generators and other	0.6	1.9
	100.0%	100.0%

SUMMER PEAK LOADS

Preliminary figures published in the 1983 Post-Summer Electric Power Survey indicated that the 1983 summer peak load was 7.5 percent above 1982. According to final data now available, the actual increase in the 1983 summer peak load was 7.9 percent.

Summer peak-load forecasts have been reduced by all reliability councils except NPCC and ERCOT. For the nine regions taken together, reductions range from 1.0 percent to 2.1 percent for the years 1984 through 1992, compared with values shown for those years in the April 1983 Electric Power Survey.

The summer peak load for the sum of the nine regions, which was 447.5 thousands megawatts in 1983, is projected to be 446.7 thousand megawatts in 1984, a decrease of 0.1 percent. For the summer of 1993, the projection is 559.4 thousand megawatts. This represents an average annual increase of 2.5 percent between the first and tenth forecast years.

SUMMER PERCENT CAPACITY MARGINS

Of the 81 summer capacity margin percentages shown for the nine-year period 1984-1992 for the nine reliability councils, 46 of the values are lower than the equivalent respective values one year previous, 32 of the percent margins are higher, and 3 are unchanged. NPCC, MAIN, and MAPP show consistently lower percent margins from 1984 through 1992, and SPP and ERCOT show more decreases than increases for the same period. ECAR and WSCC are only regions showing more increases than reductions in projected percent capacity margins.

Except for the years 1985 through 1987 which show either slight increases or no change, summer percent capacity margins for the country as a whole are lower from 1984 through 1992 generally because capability projections have been reduced more than expected peak loads. As now forecast, the summer capacity margins for the country range from 27.6 percent in 1985 and 1986 to 21.7 percent in 1993, shown in these reports for the first time.

Table 10/SUMMER CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS/1984-1993 PROJECTED (Megawatts)

Regions		1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	Growth Rate 1984-1993*
NPCC	Capability	52.556	54.028	56.122	56.658	56.344	56.290	56.283	58.839	58.504	58.396	1.2%
	Peak Load	37.881	38.446	38.931	39.532	40.306	41.043	41.673	42.344	43.200	44.006	1.7%
	Installed Margin	14.711	15.617	17.225	17.151	16.085	15.253	14.579	16.463	15.272	14.357	
	% Capacity Margin	28.0%	28.9%	30.7%	30.3%	28.5%	27.1%	25.9%	28.0%	26.1%	24.6%	
MAAC	Capability	47.013	49.315	49.126	50.013	50.015	50.390	52.324	51.363	51.095	51.276	0.8%
	Peak Load	34.720	35.180	35.760	36.140	36.690	37.140	37.580	38.060	38.610	39.150	1.3%
	Installed Margin	13.069	14.135	13.366	13.873	13.325	13.250	14.744	13.303	12.485	12.126	
	% Capacity Margin	27.3%	28.7%	27.2%	27.7%	26.6%	26.3%	28.2%	25.9%	24.4%	23.6%	
ECAR	Capability	87.096	94.049	97.535	99.040	101.029	100.729	101.044	101.982	102.693	104.284	2.0%
	Peak Load	64.008	66.275	68.236	69.774	71.438	73.047	74.579	76.150	77.664	79.110	2.4%
	Installed Margin	23.088	27.774	29.299	29.266	29.591	27.682	26.465	25.832	25.029	25.174	
	% Capacity Margin	26.5%	29.5%	30.0%	29.5%	29.3%	27.5%	26.2%	25.3%	24.4%	24.1%	
SERC	Capability	129.309	133.248	135.573	139.163	140.896	145.381	146.339	149.537	151.551	153.247	1.9%
	Peak Load	93.920	98.030	100.979	104.019	106.747	109.572	112.505	115.605	118.404	121.873	2.9%
	Installed Margin	35.389	35.218	34.594	35.144	34.149	35.809	33.834	33.932	33.147	31.374	
	% Capacity Margin	27.4%	26.4%	25.5%	25.3%	24.2%	24.6%	23.1%	22.7%	21.9%	20.5%	
MAIN	Capability	43.035	45.540	47.763	49.807	49.515	49.551	49.665	49.684	49.484	49.889	1.7%
	Peak Load	34.119	35.055	35.642	36.274	36.874	37.511	38.160	38.827	38.498	40.165	1.8%
	Installed Margin	8.916	10.485	12.121	13.533	12.641	12.040	11.505	10.857	9.986	9.724	
	% Capacity Margin	20.7%	23.0%	25.4%	27.2%	25.5%	24.3%	23.2%	21.9%	20.2%	19.5%	
SPP	Capability	60.903	66.461	67.848	67.813	67.605	67.479	68.890	70.016	69.813	71.700	1.8%
	Peak Load	46.441	47.548	48.702	50.068	51.486	52.940	54.350	55.961	57.486	58.970	2.7%
	Installed Margin	14.462	18.913	19.146	17.745	16.119	14.539	14.540	14.055	12.327	12.730	
	% Capacity Margin	23.7%	28.5%	28.2%	26.2%	23.8%	21.5%	21.1%	20.1%	17.7%	17.8%	
ERCOT	Capability	45.454	46.949	48.859	51.457	51.954	55.123	56.142	57.928	59.853	61.993	3.5%
	Peak Load	36.841	38.303	39.744	41.594	43.061	44.906	46.709	48.605	50.375	52.407	4.0%
	Installed Margin	8.613	8.646	9.115	9.863	8.893	10.217	9.433	9.323	9.478	9.586	
	% Capacity Margin	18.9%	18.4%	18.7%	19.2%	17.1%	18.5%	16.8%	16.1%	15.8%	15.5%	
MAPP	Capability	29.134	29.172	29.230	29.439	30.181	30.148	30.205	30.785	30.781	31.711	0.9%
	Peak Load	21.517	22.275	22.809	23.351	23.907	24.510	25.149	25.582	26.175	26.728	2.4%
	Installed Margin	7.617	6.897	6.421	6.088	6.274	5.638	5.056	5.203	4.606	4.983	
	% Capacity Margin	26.1%	23.6%	22.0%	20.7%	20.8%	18.7%	16.7%	16.9%	15.0%	15.7%	
WSCC	Capability	111.831	117.543	120.761	123.078	123.614	123.857	126.492	129.723	130.498	131.591	1.8%
	Peak Load	77.234	79.571	81.673	84.173	86.429	88.549	90.586	92.814	94.958	96.961	2.6%
	Installed Margin	34.597	37.972	39.088	38.905	37.185	35.308	35.906	36.909	35.540	34.630	
	% Capacity Margin	30.9%	32.3%	32.4%	31.6%	30.1%	28.5%	28.4%	28.5%	27.2%	26.3%	
TOTAL UNITED STATES**	Capability	606.331	636.305	652.917	666.468	671.153	678.948	687.384	699.857	704.272	714.087	1.8%
	Peak Load	446.681	460.683	472.476	484.925	496.938	509.218	521.291	533.948	546.370	559.370	2.5%
	Installed Margin	160.462	175.657	180.375	181.568	174.262	169.736	166.062	165.877	157.870	154.684	
	% Capacity Margin	26.4%	27.6%	27.6%	27.2%	26.0%	25.0%	24.2%	23.7%	22.4%	21.7%	

*Compound annual growth rate from 1984 to 1993

**U.S. totals are meaningless and should not be used for policy purposes

NOTE: For definitions of terms see page 5

WINTER CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS 1984-1993

WINTER CAPABILITIES

Winter 1984/85 capability now projected for the entire electric utility industry is 625.0 thousand megawatts. The new projections for 1984/85 through 1992/93 for the nine regions taken together show reduced values, ranging from 0.7 percent to 2.4 percent below the winter capabilities expected for these years twelve months ago. ERCOT is the only council that has consistently increased its winter capability projections over the whole period.

For winter 1993/94 the total capability of the industry is projected to reach 726.9 thousand megawatts. This value yields an average annual compound growth rate of 1.7 percent between the first and tenth forecast years.

The scheduled additions table on page 27 summarizes the number and aggregate ratings of new generating units that have so far been both ordered from the equipment manufacturers and been placed in the expansion program by having been assigned official scheduled dates of commercial operations. As of January 1, 1984, the furthest out year for which an ordered unit had been scheduled for operation was 1998.

WINTER PEAK LOADS

As now projected, the winter 1984/85 peak load for the contiguous U.S. is expected to be 409.3 thousand megawatts, a decline of 0.4 percent below the winter 1983/84 peak load. The new projections for 1984/85 through 1992/93 for the nine regions taken together show reduced values, ranging from 2.2 percent to 4.0 percent below the winter peak loads expected for these years twelve months ago. Except for a slight reduction in the winter of 1985/86, MAPP has raised all of its peak load projections between 0.5 percent and 2.5 percent. NPCC is the only council that has consistently increased its winter peak load projections throughout the whole period.

For winter 1993/94, the furthest out year projected in this report, the expected peak load is 511.2 thousand megawatts. This represents an average annual increase of 2.5 percent between the first and tenth forecast years.

WINTER PERCENT CAPACITY MARGINS

Compared with projected percent capacity margin values calculated on the same basis one year ago, regional winter percent margins reported in this survey are (unlike for the summer season) generally higher for all reliability councils except NPCC and MAPP. For the country as a whole, percent capacity margins are now projected to range from 35.3 percent for the winter of 1985/86 to 29.6 percent for 1993/94.

Table 11/WINTER CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS/1984/85-1993/94 PROJECTED (Megawatts)

Regions		1984/85	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91	1991/92	1992/93	1993/94	Growth Rate 1984-1993*
NPCC	Capability	53,967	54,624	57,495	57,144	57,051	57,102	59,618	59,328	59,217	60,046	1.0%
	Peak Load	36,518	36,956	37,385	37,857	38,839	39,630	40,325	41,147	41,971	42,947	1.8%
	Installed Margin	17,484	17,712	20,135	19,311	18,231	17,472	19,261	18,143	17,208	16,060	
	% Capacity Margin	32.4%	32.4%	35.0%	33.8%	31.9%	30.6%	32.3%	30.6%	29.1%	27.2%	
MAAC	Capability	50,754	51,932	51,528	52,533	52,535	52,870	54,070	53,659	53,340	53,771	0.5%
	Peak Load	30,840	31,720	32,380	33,080	33,840	34,470	35,080	35,860	36,570	37,220	2.1%
	Installed Margin	20,714	20,212	19,148	19,453	18,695	18,400	18,990	17,799	16,770	16,551	
	% Capacity Margin	40.2%	38.9%	37.2%	37.0%	35.6%	34.8%	35.1%	33.2%	31.4%	30.8%	
ECAR	Capability	94,007	97,300	100,261	100,327	101,990	103,048	103,018	103,603	105,076	106,487	1.4%
	Peak Load	64,249	66,322	68,236	70,138	71,968	73,472	75,167	76,882	78,460	79,956	2.5%
	Installed Margin	29,758	30,978	32,025	30,189	30,022	29,576	27,851	26,721	26,616	26,531	
	% Capacity Margin	31.7%	31.8%	31.9%	30.1%	29.4%	28.7%	27.0%	25.8%	25.3%	24.9%	
SERC	Capability	130,780	136,573	139,072	142,748	144,793	148,199	148,106	151,977	154,776	156,093	2.0%
	Peak Load	94,993	97,745	100,736	102,675	105,086	107,351	110,092	112,582	115,255	117,936	2.4%
	Installed Margin	35,787	38,828	38,336	40,073	39,707	40,848	38,014	39,395	39,520	38,157	
	% Capacity Margin	27.4%	28.4%	27.6%	28.1%	27.4%	27.6%	25.7%	25.9%	25.5%	24.4%	
MAIN	Capability	44,652	46,476	49,671	50,814	50,437	50,302	50,661	50,469	50,468	50,872	1.5%
	Peak Load	27,957	28,606	29,282	29,938	30,636	31,350	32,109	32,811	33,527	34,254	2.3%
	Installed Margin	16,695	17,870	20,389	20,876	19,801	18,952	18,552	17,658	16,941	16,618	
	% Capacity Margin	37.4%	38.4%	41.0%	41.1%	39.3%	37.7%	36.6%	35.0%	33.6%	32.7%	
SPP	Capability	61,757	67,891	68,121	67,933	67,869	67,667	69,327	70,027	70,188	72,126	1.7%
	Peak Load	34,527	35,586	36,704	37,798	38,966	40,217	41,444	42,804	44,118	45,433	3.1%
	Installed Margin	27,230	32,305	31,417	30,135	28,903	27,450	27,883	27,223	26,070	26,693	
	% Capacity Margin	44.1%	47.6%	46.1%	44.4%	42.6%	40.6%	40.2%	38.9%	37.1%	37.0%	
ERCOT	Capability	46,605	47,089	49,385	51,581	53,428	55,677	56,628	58,133	60,655	62,788	3.4%
	Peak Load	27,977	28,748	30,094	31,414	32,640	34,196	35,639	37,218	38,745	40,232	4.1%
	Installed Margin	18,628	18,341	19,291	20,167	20,788	21,481	20,989	20,915	21,920	22,556	
	% Capacity Margin	40.0%	38.9%	39.1%	39.1%	38.9%	38.6%	37.1%	36.0%	36.1%	35.9%	
MAPP	Capability	29,121	28,905	29,303	29,960	30,016	30,039	30,809	30,759	31,248	32,476	1.2%
	Peak Load	18,982	19,663	20,246	20,820	21,418	22,001	22,551	23,063	23,617	24,134	2.7%
	Installed Margin	10,139	9,242	9,057	9,140	8,598	8,038	8,258	7,696	7,631	8,342	
	% Capacity Margin	34.8%	32.0%	30.9%	30.5%	28.6%	26.8%	26.8%	25.0%	24.4%	25.7%	
WSCC	Capability	113,361	119,529	121,780	123,938	124,248	125,918	127,063	130,088	131,311	132,243	1.7%
	Peak Load	73,208	75,414	77,427	79,559	81,387	83,445	85,413	87,514	89,484	89,040	2.2%
	Installed Margin	40,153	44,115	44,353	44,379	42,861	42,473	41,650	42,574	41,827	43,203	
	% Capacity Margin	35.4%	36.9%	36.4%	35.8%	34.5%	33.7%	32.8%	32.7%	31.9%	32.7%	
TOTAL UNITED STATES**	Capability	625,004	650,319	666,616	676,978	682,367	690,822	699,300	708,043	716,279	726,902	1.7%
	Peak Load	409,251	420,760	432,490	443,279	454,780	466,132	477,820	489,881	501,747	511,152	2.5%
	Installed Margin	216,588	229,603	234,151	233,723	227,606	224,690	221,448	218,124	214,503	214,711	
	% Capacity Margin	34.6%	35.3%	35.1%	34.5%	33.4%	32.5%	31.7%	30.8%	29.9%	29.6%	

*Compound annual growth rate from 1984/85 to 1993/94

**U.S. totals are meaningless and should not be used for policy purposes.

NOTE: For definitions of terms see page 5

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS 1984-1993

The relationship between the summer and winter peak loads in the different regions of the country, and also for the contiguous United States, are shown in the accompanying table, where the summer peak load in each case is expressed as a percentage of the winter peak load for the following season.

Though there are some changes from year to year in the regional ratios, the movements are generally offsetting to the extent that the summer/winter ratio for the sum of the nine regions calculates to a constant 109 percent throughout the ten-year period.

Table 12/SUMMER PEAK LOADS EXPRESSED AS PERCENTAGE OF PEAK LOADS FOR THE FOLLOWING WINTER/1984-1993

Regions	84/85	85/86	86/87	87/88	88/89	89/90	90/91	91/92	92/93	93/94
NPCC	104	104	104	104	104	104	103	103	103	102
MAAC	113	111	110	109	108	108	107	106	106	105
ECAR	100	100	100	99	99	99	99	99	99	99
SERC	99	100	100	101	102	102	102	103	103	103
MAIN	122	123	122	121	120	120	119	118	118	117
SPP	135	134	133	132	132	132	131	131	130	130
ERCOT	132	133	132	132	132	131	131	131	130	130
MAPP	113	113	113	112	112	111	112	111	111	111
WSCC	105	106	105	106	106	106	106	106	106	109
U.S.TOTAL	109	109	109	109	109	109	109	109	109	109

ANNUAL ENERGY REQUIREMENTS AND ANNUAL LOAD FACTORS 1984-1993

Calendar-year energy requirements by region and for the total of the lower forty-eight states are shown in Table 13. The corresponding annual load factors are given in Table 14. The energy requirement represents utility generation plus megawatthours received from all outside sources, including net imports from other countries and energy from certain industrial installations which are interconnected and coordinated with the utility systems.

The present projections of energy requirements for the contiguous United States for the years 1984 through 1992 range between 2.5 and 5.1 percent below the values predicted in the previous report of April 1, 1983. For 1993, the new furthest out year, the projected megawatthour requirement is 3.0 billion megawatthours. This represents an average annual increase of 2.7 percent between the first and tenth forecast years.

Table 13/ANNUAL ENERGY REQUIREMENTS (Megawatthours in Thousands)/1984-1993

Regions	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	Growth Rate 1984-1993*
NPCC	211,743	214,724	217,532	221,409	225,966	230,912	235,186	239,781	245,372	250,626	1.9%
MAAC	180,491	184,345	187,366	190,168	194,020	197,320	200,735	204,383	207,931	211,483	1.8%
ECAR	370,800	383,900	394,600	404,700	416,500	426,600	434,700	443,300	451,800	459,900	2.4%
SERC	501,721	525,733	542,748	561,472	576,164	591,681	607,757	623,416	640,066	655,883	3.0%
MAIN	161,901	170,168	174,854	179,904	183,623	187,533	191,390	195,152	198,954	202,789	2.3%
SPP	222,503	230,312	236,640	243,839	251,102	258,718	266,278	274,537	283,073	290,555	3.0%
ERCOT	185,020	191,831	197,374	206,175	214,224	223,378	232,977	242,531	252,181	262,535	4.0%
MAPP	104,764	108,308	112,169	115,599	119,172	122,390	125,746	128,574	131,940	135,138	2.9%
WSCC	448,200	462,075	477,521	490,456	504,217	517,532	530,536	544,295	558,181	570,941	2.5%
TOTAL U.S.	2,390,143	2,471,396	2,540,804	2,613,722	2,684,988	2,756,064	2,825,305	2,895,969	2,969,498	3,039,850	2.7%

*Compound annual growth rate from 1984 to 1993.

Table 14/ANNUAL LOAD FACTOR, %/1984-1993

Regions	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
NPCC	65.4	63.8	63.8	63.9	63.8	64.2	64.4	64.6	64.7	65.0
MAAC	59.2	59.8	59.8	60.1	60.2	60.6	61.0	61.3	61.3	61.7
ECAR	65.7	66.1	66.0	66.2	65.9	66.3	66.0	65.8	65.6	65.7
SERC	60.1	61.2	61.4	61.6	61.4	61.6	61.7	61.6	61.5	61.4
MAIN	55.0	55.4	56.0	56.6	56.7	57.1	57.3	57.4	57.3	57.6
SPP	54.5	55.3	55.5	55.6	55.5	55.8	55.9	56.0	56.1	56.2
ERCOT	57.2	57.2	56.7	56.6	56.6	56.8	56.9	57.0	57.0	57.2
MAPP	55.4	55.5	56.1	56.5	56.7	57.0	57.1	57.4	57.4	57.7
WSCC	66.1	66.3	66.7	66.5	66.3	65.9	66.2	66.6	66.3	65.9
TOTAL U.S.	60.9	61.2	61.4	61.5	61.4	61.6	61.7	61.8	61.7	61.7

FUTURE EXPANSION PROGRAM

Table 16 shows that as of January 1, 1984, the electric power systems serving the contiguous United States had on order with both domestic and foreign manufacturers, and scheduled for commercial operation during 1984 and later years, a total of 110.0 thousand megawatts. This included 48 hydraulic units of both conventional and pumped-storage type, totaling 6.2 thousand megawatts. The thermal units include steam turbine-generators, of both conventional and nuclear types, and combustion turbine-generators. Some of this capacity is on site and being installed; the remainder is under manufacture or in the form of firm orders.

During 1984, 13 nuclear power units are scheduled for commercial operation. These 13 units have an aggregate capability of 14.5 thousand megawatts. As of January 1, 1984 there are 38 additional nuclear units on order and scheduled for commercial operation in 1985 and later in the contiguous United States, having an aggregate capability of 42.5 thousand megawatts. These units are included in the regional listing designated Table 17.

An indeterminate number of units, amounting to several thousand megawatts, are also on order but are either awaiting their first assignment of a scheduled date of commercial operation by the utility systems, or were once scheduled and have since been removed from the expansion program. It is probable that the majority of the orders in the second category [being held open as options by the manufacturers] will not be reactivated.

Table 15 shows that, of the total 104.7 thousand megawatts of steam turbine-generators on order as of January 1, 1984, and scheduled for service, nuclear and conventional units in sizes 700 megawatts and larger account for 70.5 percent of the total. Among units with ratings less than 100 megawatts, there are four geothermal units with a total capability of 175 megawatts, one solar unit for 10 megawatts, and one wood-burning unit rated at 50 megawatts.

Table 15/NUMBER AND AGGREGATE CAPABILITY OF STEAM TURBINE-GENERATORS IN THE EXPANSION PROGRAM GROUPED ACCORDING TO SIZE RANGE As of January 1, 1984

Size Range, mW	No. Of Units	Aggregate Capability mW	Percent of Total
1,300 mW and Larger	2	2,600	2.5
1,200 to 1,299	13	16,133	15.4
1,100 to 1,199	22	25,033	23.9
1,000 to 1,099	9	9,642	9.2
900 to 999	4	3,690	3.5
800 to 899	10	8,087	7.7
700 to 799	12	8,742	8.3
600 to 699	21	13,442	12.8
500 to 599	13	6,733	6.4
400 to 499	14	6,122	5.8
300 to 399	8	2,844	2.7
200 to 299	4	960	0.9
100 to 199	4	438	0.4
Under 100	6	235	0.2
TOTAL STEAM UNITS	142	104,701	100.0

Table 16/SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPABILITY BASED ON SCHEDULED DATES OF COMMERCIAL OPERATION AS OF JANUARY 1, 1984
In Terms of Capability Ratings of the Units

	THERMAL								HYDRAULIC					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine-Generators		Conventional		Pumped Storage		Total	
	Nuclear		Conventional											
	No. of Units	mW	No. of Units	mW	No. of Units	mW	No. of Units	mW	No. of Units	mW	No. of Units	mW	No. of Units	mW
TOTAL SCHEDULED	51	56.946	91	47.756	1	50	–	–	34	1.849	14	4.362	191	110.963
SCHEDULED ADDITIONS BY YEARS – as of January 1, 1984														
1984	13	14.459	18	8.721	–	–	–	–	15	730	4	1.214	50	25.124
1985	11	12.083	18	7.793	–	–	–	–	14	815	4	1.400	47	22.091
1986	13	13.765	10	5.665	1	50	–	–	5	304	2	700	31	20.484
1987	4	4.665	7	4.034	–	–	–	–	–	–	–	–	11	8.699
1988	2	2.355	5	2.410	–	–	–	–	–	–	2	483	9	5.248
1989	3	3.702	4	2.974	–	–	–	–	–	–	2	565	9	7.241
1990	2	2.305	6	3.710	–	–	–	–	–	–	–	–	8	6.015
1991	3	3.612	8	4.336	–	–	–	–	–	–	–	–	11	7.948
1992	–	–	2	708	–	–	–	–	–	–	–	–	2	708
1993	–	–	5	2.955	–	–	–	–	–	–	–	–	5	2.955
1994	–	–	1	650	–	–	–	–	–	–	–	–	1	650
1995	–	–	2	875	–	–	–	–	–	–	–	–	2	875
1996	–	–	1	500	–	–	–	–	–	–	–	–	1	500
1997	–	–	3	1.925	–	–	–	–	–	–	–	–	3	1.925
1998	–	–	1	500	–	–	–	–	–	–	–	–	1	500
SCHEDULED ADDITIONS BY REGION – as of January 1, 1984														
NPCC	5	5.339	2	675	–	–	–	–	1	8	–	–	8	6.022
MAAC	4	4.227	5	2.902	–	–	–	–	5	190	–	–	14	7.319
ECAR	5	5.141	13	8.351	–	–	–	–	–	–	–	–	18	13.492
SERC	11	12.333	15	9.194	–	–	–	–	11	648	9	2.948	46	25.123
MAIN	8	8.706	2	960	–	–	–	–	–	–	–	–	10	9.666
SPP	5	5.694	10	6.274	–	–	–	–	1	28	1	32	17	12.028
ERCOT	4	4.800	12	7.740	–	–	–	–	–	–	–	–	16	12.540
MAPP	–	–	5	2.478	–	–	–	–	1	38	–	–	6	2.516
WSCC	9	10.705	27	9.182	1	50	–	–	15	937	4	1.382	56	22.256
SCHEDULED ADDITIONS BY OWNERSHIP – as of January 1, 1984														
INVESTOR-OWNED	44	48.592	67	38.184	–	–	–	–	10	486	13	4.330	134	91.592
FEDERAL	4	4.763	–	–	–	–	–	–	11	659	1	32	16	5.454
MUNICIPAL	–	–	6	3.037	1	50	–	–	8	528	–	–	15	3.615
COOPERATIVE	–	–	9	3.925	–	–	–	–	–	–	–	–	9	3.925
STATE AND LOCAL	3	3.590	9	2.160	–	–	–	–	5	176	–	–	17	6.376

Table 17/SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPABILITY
Based on Scheduled Dates of Commercial Operation as of January 1, 1984

Includes all electric generating units 4,000 kw and larger on order and scheduled for service by the U.S. Electric Power Systems.

SYMBOLS

Investor-Owned	I
Federal	F
Municipal	M
Cooperative	C
State & Local	SL
Thermal	
Conventional steam turbine-generator	T
Nuclear steam turbine-generator	N
Combustion turbine-generator	G
Diesel engine-generator	D
Hydraulic	
Hydraulic turbine-generator	H
Pumped-Storage	
Pumped-Storage turbine-generator	S
Reversible pumped-storage turbine-generator	R
Combined-Cycle	
Combustion turbine-generator for combined-cycle operation	GC
Conventional steam turbine-generator for combined-cycle operation	TC

° Denotes units added to the expansion program since October 1, 1983.

+ Denotes multiple ownership of the unit. In such cases, the name of the participating power system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the power system shown is the first in alphabetical order among the major participants.

NOTES: Megawatts shown for individual generating units represent, in most cases, the net operating capability expected by the power systems; in other cases they represent the manufacturer's nameplate rating of the unit.

SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	mW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
NPCC:						
BURLINGTON VERMONT	McNEIL NO 1	M	T	Wood	50	1984
CENTRAL MAINE POWER CO	HIRAM	I	H		8	1985
LONG ISLAND LIGHTING CO	SHOREHAM NO 1	I	N		809	1985
+NIAGARA MOHAWK POWER CORP	NINE MILE POINT NO 2	I	N		1,080	1986
+NORTHEAST UTILITIES	MILLSTONE POINT NO 3	I	N		1,150	1986
NY STATE ELECTRIC & GAS CO	SOMERSET NO 1	I	T	Coal	625	1984
+PUBLIC SERVICE CO OF NEW HAMPSHIRE	SEABROOK NO 1	I	N		1,150	1986
+PUBLIC SERVICE CO OF NEW HAMPSHIRE	SEABROOK NO 2	I	N		1,150	1991
MAAC:						
BALTIMORE GAS & ELECTRIC CO	BRANDON SHORES NO 1	I	T	Oil/Coal	637	1984
BALTIMORE GAS & ELECTRIC CO	BRANDON SHORES NO 2	I	T	Oil/Coal	640	1988
DELMARVA POWER & LIGHT CO	VIENNA NO 9	I	T	Coal	375	1995
GENERAL PUBLIC UTILITIES	COAL NO 1	I	T	Coal	625	1993
GENERAL PUBLIC UTILITIES	COAL NO 2	I	T	Coal	625	1997
+PENNSYLVANIA POWER & LIGHT CO	SUSQUEHANNA NO 2	I	N		1,050	1984
PHILADELPHIA ELECTRIC CO	LIMERICK NO 1	I	N		1,055	1985
PHILADELPHIA ELECTRIC CO	LIMERICK NO 2	I	N		1,055	1990
+PUBLIC SERVICE ELECTRIC & GAS CO	HOPE CREEK NO 1	I	N		1,067	1986
SAFE HARBOR WATER CORPORATION	SAFE HARBOR NO 8	I	H		38	1985
SAFE HARBOR WATER CORPORATION	SAFE HARBOR NO 9	I	H		38	1986
SAFE HARBOR WATER CORPORATION	SAFE HARBOR NO 10	I	H		38	1985
SAFE HARBOR WATER CORPORATION	SAFE HARBOR NO 11	I	H		38	1986
SAFE HARBOR WATER CORPORATION	SAFE HARBOR NO 12	I	H		38	1985
ECAR:						
AMERICAN ELECTRIC POWER CO	ROCKPORT NO 1	I	T	Coal	1,300	1984
AMERICAN ELECTRIC POWER CO	ROCKPORT NO 2	I	T	Coal	1,300	1986
BIG RIVERS ELECTRIC CORP	D B WILSON NO 1	C	T	Coal	395	1984
+CLEVELAND ELECTRIC ILLUMINATING CO	PERRY NO 1	I	N		1,205	1985
+CLEVELAND ELECTRIC ILLUMINATING CO	PERRY NO 2	I	N		1,205	1988
CONSUMERS POWER CO	MIDLAND NO 2	I	N		805	1986
+DETROIT EDISON COMPANY	BELLE RIVER NO 1	I	T	Coal	676	1984
DETROIT EDISON COMPANY	BELLE RIVER NO 2	I	T	Coal	676	1985
+DETROIT EDISON COMPANY	FERMI NO 2	I	N		1,093	1984
+DUQUESNE LIGHT COMPANY	BEAVER VALLEY NO 2	I	N		833	1986
EAST KENTUCKY POWER COOP	SMITH NO 1	C	T	Coal	600	1992
INDIANAPOLIS POWER & LIGHT CO	PETERSBURG NO 4	I	T	Coal	515	1986
KENTUCKY UTILITIES CO	GHENT NO 4	I	T	Coal	500	1984
KENTUCKY UTILITIES CO	HANCOCK NO 1	I	T	Coal	650	1993
KENTUCKY UTILITIES CO	HANCOCK NO 2	I	T	Coal	650	1994
LOUISVILLE GAS & ELECTRIC CO	TRIMBLE COUNTY NO 1	I	T	Coal	495	1987
NORTHERN INDIANA PUBLIC SERVICE CO	SCHAHFER NO 18	I	T	Coal	344	1986
SOUTHERN INDIANA GAS & ELECTRIC CO	BROWN NO 2	I	T	Coal	250	1986

SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	mW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
SERC:						
ALABAMA POWER COMPANY	MILLER NO 2	I	T	Coal	666	1985
ALABAMA POWER COMPANY	MILLER NO 3	I	T	Coal	666	1989
ALABAMA POWER COMPANY	MILLER NO 4	I	T	Coal	666	1991
ALABAMA POWER COMPANY	MITCHELL NO 5	I	H		64	1985
ALABAMA POWER COMPANY	MITCHELL NO 6	I	H		64	1985
ALABAMA POWER COMPANY	MITCHELL NO 7	I	H		64	1985
CAROLINA POWER & LIGHT CO	HARRIS NO 1	I	N		900	1986
CAROLINA POWER & LIGHT CO	MAYO NO 2	I	T	Coal	720	1991
DUKE POWER COMPANY	CATAWBA NO 1	I	N		1,145	1985
DUKE POWER COMPANY	CATAWBA NO 2	I	N		1,145	1987
DUKE POWER COMPANY	McGUIRE NO 2	I	N		1,180	1984
FLORIDA POWER CORPORATION	CRYSTAL RIVER NO 5	I	T	Coal	670	1984
oGEORGIA POWER COMPANY	BARTLETTS FERRY 5 & 6	I	H		96	1985
GEORGIA POWER COMPANY	ROCKY MOUNTAIN NO 1	I	R		283	1989
GEORGIA POWER COMPANY	ROCKY MOUNTAIN NO 2	I	R		283	1988
GEORGIA POWER COMPANY	ROCKY MOUNTAIN NO 3	I	R		283	1989
+GEORGIA POWER COMPANY	SCHERER NO 2	I	T	Coal	808	1984
+GEORGIA POWER COMPANY	SCHERER NO 3	I	T	Coal	808	1987
+GEORGIA POWER COMPANY	SCHERER NO 4	I	T	Coal	808	1989
+GEORGIA POWER COMPANY	VOGTLE NO 1	I	N		1,150	1987
+GEORGIA POWER COMPANY	VOGTLE NO 2	I	N		1,150	1988
+JACKSONVILLE FLORIDA	ST JOHNS RIVER PARK 1	M	T	Coal	525	1987
+JACKSONVILLE FLORIDA	ST JOHNS RIVER PARK 2	M	T	Coal	525	1988
+ORLANDO FLORIDA	STANTON NO 1	M	T	Coal	415	1987
SEMINOLE ELECTRIC COOP	SEMINOLE NO 2	C	T	Coal	600	1985
+SOUTH CAROLINA ELECTRIC & GAS CO	SUMMER NO 1	I	N		900	1984
SOUTH CAROLINA PUBLIC SERVICE AUTHY	CROSS NO 1	SL	T	Coal	450	1991
SOUTH CAROLINA PUBLIC SERVICE AUTHY	CROSS NO 2	SL	T	Coal	450	1984
TAMPA ELECTRIC COMPANY	BIG BEND NO 4	I	T	Coal	417	1985
TENNESSEE VALLEY AUTHORITY	BELLEFONTE NO 1	F	N		1,212	1989
TENNESSEE VALLEY AUTHORITY	BELLEFONTE NO 2	F	N		1,212	1991
TENNESSEE VALLEY AUTHORITY	WATTS BAR NO 1	F	N		1,170	1984
TENNESSEE VALLEY AUTHORITY	WATTS BAR NO 2	F	N		1,170	1986
U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 1	F	H		75	1984
U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 2	F	H		75	1984
U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 3	F	H		75	1985
U S ARMY CORPS OF ENGINEERS	R B RUSSELL NO 4	F	H		75	1985
U S ARMY CORPS OF ENGINEERS	ST STEPHEN NO 1	F	H		20	1984
U S ARMY CORPS OF ENGINEERS	ST STEPHEN NO 2	F	H		20	1984
U S ARMY CORPS OF ENGINEERS	ST STEPHEN NO 3	F	H		20	1984
+VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 1	I	R		350	1985
+VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 2	I	R		350	1985
+VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 3	I	R		350	1985
+VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 4	I	R		350	1985
+VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 5	I	R		350	1986
+VIRGINIA ELECTRIC & POWER CO	BATH COUNTY NO 6	I	R		350	1986

SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	mW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
MAIN:						
COMMONWEALTH EDISON CO	BRAIDWOOD NO 1	I	N		1,120	1986
COMMONWEALTH EDISON CO	BRAIDWOOD NO 2	I	N		1,120	1987
COMMONWEALTH EDISON CO	BYRON NO 1	I	N		1,120	1985
COMMONWEALTH EDISON CO	BYRON NO 2	I	N		1,120	1986
COMMONWEALTH EDISON CO	LASALLE COUNTY NO 1	I	N		1,078	1984
COMMONWEALTH EDISON CO	LASALLE COUNTY NO 2	I	N		1,078	1984
+ILLINOIS POWER COMPANY	CLINTON NO 1	I	N		950	1986
UNION ELECTRIC COMPANY	CALLAWAY NO 1	I	N		1,120	1985
WISCONSIN ELECTRIC POWER CO	PLEASANT PRAIRIE NO 2	I	T	Coal	580	1985
+WISCONSIN POWER & LIGHT CO	EDGEWATER NO 5	I	T	Coal	380	1985
SPP:						
+ARKANSAS POWER & LIGHT CO	INDEPENDENCE NO 2	I	T	Coal	816	1985
GRAND RIVER DAM AUTHORITY	CHOUTEAU NO 2	SL	T	Coal	490	1985
GULF STATES UTILITIES	NELSON NO 5	I	T	Coal	540	1993
+GULF STATES UTILITIES	RIVER BEND NO 1	I	N		940	1985
+KANSAS GAS & ELECTRIC CO	WOLF CREEK NO 1	I	N		1,150	1985
LOUISIANA POWER & LIGHT CO	WATERFORD NO 3	I	N		1,104	1984
LOUISIANA POWER & LIGHT CO	WILTON NO 1	I	T	Coal	800	1993
LOUISIANA POWER & LIGHT CO	WILTON NO 2	I	T	Coal	800	1997
+MISSISSIPPI POWER & LIGHT CO	GRAND GULF NO 1	I	N		1,250	1984
+MISSISSIPPI POWER & LIGHT CO	GRAND GULF NO 2	I	N		1,250	1990
OKLAHOMA GAS & ELECTRIC CO	MUSKOGEE NO 6	I	T	Coal	515	1984
+SOUTHWESTERN ELECTRIC POWER CO	DOLET HILLS NO 1	I	T	Coal	640	1986
+SOUTHWESTERN PUBLIC SERVICE CO	PIRKEY NO 1	I	T	Coal	640	1985
oSOUTHWESTERN PUBLIC SERVICE CO	SO PLAINS STA NO 6	I	T	Coal	525	1990
SOUTHWESTERN PUBLIC SERVICE CO	TOLK NO 2	I	T	Coal/Oil/Gas	508	1985
U S ARMY CORPS OF ENGINEERS	CANNON NO 1	F	R		32	1984
U S ARMY CORPS OF ENGINEERS	CANNON NO 2	F	H		28	1984

SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	mW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
ERCOT:						
+BRAZOS ELECTRIC POWER COOP	SAN MIGUEL NO 2	C	T	Coal/Oil	400	1991
+CENTRAL POWER & LIGHT CO	COLETO CREEK NO 2	I	T	Coal	700	1990
HOUSTON LIGTING & POWER CO	LIMESTONE NO 1	I	T	Coal	700	1986
HOUSTON LIGTING & POWER CO	LIMESTONE NO 2	I	T	Coal	700	1987
HOUSTON LIGTING & POWER CO	MALAKOFF NO 1	I	T	Coal	600	1990
HOUSTON LIGTING & POWER CO	MALAKOFF NO 2	I	T	Coal	600	1991
+HOUSTON LIGTING & POWER CO	SOUTH TEXAS NO 1	I	N		1,250	1987
+HOUSTON LIGTING & POWER CO	SOUTH TEXAS NO 2	I	N		1,250	1989
+LOWER COLORADO RIVER AUTHORITY	FAYETTE NO 3	SL	T	Coal	400	1988
+TEXAS UTILITIES CO SYSTEM	COMANCHE PEAK NO 1	I	N		1,150	1985
+TEXAS UTILITIES CO SYSTEM	COMANCHE PEAK NO 2	I	N		1,150	1986
+TEXAS UTILITIES CO SYSTEM	FOREST GROVE NO 1	I	T	Coal	750	1989
+TEXAS UTILITIES CO SYSTEM	MARTIN LAKE NO 4	I	T	Coal	750	1991
+TEXAS UTILITIES CO SYSTEM	TWIN OAK NO 1	I	T	Coal	750	1989
+TEXAS UTILITIES CO SYSTEM	TWIN OAK NO 2	I	T	Coal	750	1990
+WEST TEXAS UTILITIES	OKLAUNION NO1	I	T	Coal	640	1986
MAPP:						
BASIN ELECTRIC POWER COOP	ANTELOPE VALLEY NO 1	C	T	Coal	460	1984
+BASIN ELECTRIC POWER COOP	ANTELOPE VALLEY NO 2	C	T	Coal	460	1986
+IOWA ELECTRIC LIGHT & POWER CO	GUTHRIE COUNTY NO 1	I	T	Coal	650	1990
NEBRASKA PUBLIC POWER DISTRICT	KINGSLEY NO 1	SL	H		38	1985
+NORTHERN STATES POWER CO	SHERBURNE COUNTY NO 3	I	T	Coal	800	1988
OTTER TAIL POWER COMPANY	SPIRITWOOD NO 1	I	T	Coal	108	1992
WSCC:						
ARIZONA PUBLIC SERVICE CO	CHOLLA NO 5	I	T	Coal	340	1993
+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 1	I	N		1,270	1984
+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 2	I	N		1,270	1985
+ARIZONA PUBLIC SERVICE CO	PALO VERDE NO 3	I	N		1,270	1986
oCALIFORNIA DEPT OF WATER RESOURCES	ALAMO NO 1	SL	H		17	1985
CALIFORNIA DEPT OF WATER RESOURCES	BOTTLE ROCK	SL	T	Geothermal	55	1984
CALIFORNIA DEPT OF WATER RESOURCES	SOUTH GEYSERS	SL	T	Geothermal	55	1986
COLORADO-UTE ELECTRIC ASSOCIATION	CRAIG NO 3	C	T	Coal	400	1984

SYSTEM	UNIT	OWNER-SHIP [sic]	TYPE	FOSSIL FUELS	mW of NET EXPECTED CAPABILITY	YEAR OPTN
WSCC, continued:						
DESERET G & T COOP	BONANZA NO 1	C	T	Coal	400	1985
oGRANT COUNTY PUB UTILITY DISTRICT	QUINCY CHUTE	SL	H		9	1984
+LOS ANGELES CALIFORNIA	INTERMOUNTAIN NO 1	M	T	Coal	761	1986
+LOS ANGELES CALIFORNIA	INTERMOUNTAIN NO 2	M	T	Coal	761	1987
METROPOLITAN WATER DISTRICT	RED MOUNTAIN NO 1	M	H		6	1984
METROPOLITAN WATER DISTRICT	VALLEY VIEW NO 1	M	H		4	1985
+MONTANA POWER COMPANY	COLSTRIP NO 3	I	T	Coal	700	1984
+MONTANA POWER COMPANY	COLSTRIP NO 4	I	T	Coal	700	1985
oNORTHERN CALIFORNIA POWER AGENCY	GEOTHERMAL NO 3	SL	T	Geothermal	110	1985
PACIFIC GAS & ELECTRIC CO	DIABLO CANYON NO 1	I	N		1,086	1984
PACIFIC GAS & ELECTRIC CO	DIABLO CANYON NO 2	I	N		1,119	1985
PACIFIC GAS & ELECTRIC CO	GEYSERS NO 16	I	T	Geothermal	110	1985
PACIFIC GAS & ELECTRIC CO	GEYSERS NO 20	I	T	Geothermal	110	1985
PACIFIC GAS & ELECTRIC CO	HELMS NO 1	I	R		394	1984
PACIFIC GAS & ELECTRIC CO	HELMS NO 2	I	R		394	1984
PACIFIC GAS & ELECTRIC CO	HELMS NO 3	I	R		394	1984
PLAINS ELECTRIC G & T COOP	PEGS NO 1	C	T	Coal	210	1984
PLATTE RIVER POWER AUTHORITY	RAWHIDE NO 1	SL	T	Coal	250	1984
PUBLIC SERVICE CO OF COLORADO	PAWNEE NO 2	I	T	Coal	485	1990
+PUBLIC SERVICE CO OF NEW MEXICO	NEW MEXICO STATION NO 1	I	T	Coal	500	1995
PUBLIC SERVICE CO OF NEW MEXICO	NEW MEXICO STATION NO 2	I	T	Coal	500	1996
PUBLIC SERVICE CO OF NEW MEXICO	NEW MEXICO STATION NO 3	I	T	Coal	500	1997
PUBLIC SERVICE CO OF NEW MEXICO	NEW MEXICO STATION NO 4	I	T	Coal	500	1998
SACRAMENTO CALIFORNIA	JONES FORK	M	H		10	1986
oSACRAMENTO CALIFORNIA	McCLELLAN AFB CT NO 1	M	G		50	1986
SALT RIVER POWER DISTRICT	CORONADO NO 3	SL	T	Coal	350	1991
SAN DIEGO GAS & ELECTRIC CO	HEBER NO 2	I	T	Geothermal	45	1988
oSEATTLE WASHINGTON	BOUNDARY NO 55	M	H		196	1985
oSEATTLE WASHINGTON	BOUNDARY NO 56	M	H		196	1986
+SIERRA PACIFIC POWER CO	VALMY NO 2	I	T	Coal	250	1985
oSNOHOMISH PUBLIC UTILITY DISTRICT	SULTAN A NOS 1 & 2	SL	H		95	1984
oSNOHOMISH PUBLIC UTILITY DISTRICT	SULTAN B NOS 1 & 2	SL	H		17	1984
oSOUTHERN CALIFORNIA EDISON CO	BALSAM MEADOW NO 1	I	R		200	1988
+SOUTHERN CALIFORNIA EDISON CO	SAN ONOFRE NO 3	I	N		1,100	1984
+SOUTHERN CALIFORNIA EDISON CO	SOLAR ONE	I	T	Solar	10	1985
oTACOMA WASHINGTON	MAIN CANAL HEADWORKS	M	H		22	1986
+TACOMA WASHINGTON	SUMMER FALLS NO 1	M	H		47	1984
+TACOMA WASHINGTON	SUMMER FALLS NO 2	M	H		47	1984
TUCSON ELECTRIC POWER CO	SPRINGERVILLE NO 1	I	T	Coal	330	1985
TUCSON ELECTRIC POWER CO	SPRINGERVILLE NO 2	I	T	Coal	330	1987
U S ARMY CORPS OF ENGINEERS	LIBBY NO 5	F	H		121	1984
U S BUREAU OF RECLAMATION	GRAND COULEE PG-12	F	H		50	1984
U S BUREAU OF RECLAMATION	MT ELBERT NO 2	F	H		100	1984
UTAH POWER & LIGHT CO	HUNTER NO 4	I	T	Coal	400	1991
UTAH POWER & LIGHT CO	MILFORD GEOTHERMAL	I	T	Geothermal	20	1984
+WASHINGTON PUB PWR SPLY SYSTEM	WNP NO 2	SL	N		1,100	1984
+WASHINGTON PUB PWR SPLY SYSTEM	WNP NO 3	SL	N		1,240	1989
+WASHINGTON PUB PWR SPLY SYSTEM	WNP NO 1	SL	N		1,250	1991

NO. OF UNITS = 191 mW of EXPECTED NET CAPABILITY = 110,963

PART III / MANUFACTURE OF HEAVY ELECTRIC POWER EQUIPMENT

(HISTORICAL AND SCHEDULED)

Data in this section of the report relate to the manufacture in the United States of heavy electric power equipment for U.S. electric power systems, U.S. Industrials and for export to customers outside the United States. Information is also included on actual and scheduled imports of such equipment by U.S. electric power systems.

Orders placed with domestic and foreign manufacturers during 1983 for this type of equipment by U.S. electric power systems are shown in the accompanying order synopsis table (Table 18), together with corresponding information for the previous four years.

Detailed data concerning 1983 orders, shipments, scheduled shipments, and total production backlogs as of January 1, 1984 are shown on the following pages, as well as data on imports of equipment by U.S. electric power systems.

During 1983, orders for new electric generating units, steam and hydraulic, placed with domestic manufacturers totaled only 28 machines aggregating 1,537 megawatts. U.S. electric power systems accounted for 48.4 percent of this total capacity.

Orders placed in 1983 with foreign manufacturers by U.S. electric power systems included four steam turbine-generators aggregating 186 megawatts, seven generators for hydraulic turbines totaling 842 megawatts, and one combustion turbine-generator rated at 75 megawatts.

Production by domestic manufacturers during the year 1983 amounted to 12.2 thousand megawatts, of which 5.9 thousand megawatts were delivered to U.S. electric power systems. The total production scheduled as of January 1, 1984, for all classes of customers amounts to 143 units totaling 65.8 thousand megawatts. The manufacturing schedule for 1984 totals 11.2 thousand megawatts. The 1985 and later schedule, up to now, calls for the production of 97 units totaling 54.6 thousand megawatts.

Table 18/CAPACITIES OF VARIOUS TYPES OF EQUIPMENT ORDERED BY U.S. ELECTRIC POWER SYSTEMS FROM DOMESTIC AND FOREIGN MANUFACTURERS

		1979	1980	1981	1982	1983
Electric Generating Units (4,000 kW and Larger)						
Steam Turbine-Generators, kW						
Conventional		4,416,110	2,846,000 (a)	7,32[illegible]394 (a)		591,465
Nuclear						
Geothermal, kW		50,000		380,100	93,500	110,000
Solar, kW		12,800				14,700
Combustion Turbine-Generators, kW		428,900	551,190	524,580	35,790	75,000 (a)
Generators for Hydraulic Turbines, kW		969,280 (a)	15,010	209,340 (a)	279,326 (a)	869,367 (a)
	TOTALS	5,877,090 (a)	3,412,200 (a)	8,438,414 (a)	408,616 (a)	1,660,532 (a)
Steam Generators, 1,000 Lb Steam Per Hour		17,697	34,363	51,880	1,000	4,700
Nuclear Power Reactors (50,000 kWe and Larger)						
Hydraulic Turbines, Hp		16,000	17,600	40,000		
Power Transformers, Mva (b)		132,317	123,037	91,093	78,003	69,495

(a) Includes equipment on order with foreign manufacturers.
(b) Includes U.S. Industrials.

Table 19/MANUFACTURE OF ELECTRIC GENERATING EQUIPMENT—STEAM AND HYDRAULIC UNITS* (4,000 kW and Larger)

Customer	Shipped	Scheduled as of January 1, 1984		Total Scheduled for Shipment as of 1 1 84	New Orders Booked 1983
	1983	1984	1985 and Later		
U S Electric Power Systems					
Units	18	20	78	98	6
kW	5 937 825	6 775 585	49 736 753	56 512 338	743 532
U S Industrials					
Units	6	18	11	29	21
kW	222 828	627 874	305 422	933 296	661 954
Exports from U S					
Units	15	8	8	16	1
kW	6 017 249	3 835 574	4 518 992	8 354 566	132 000
Total					
Units	39	46	97	143	28
kW	12 177 902	11 239 033	54 561 167	65 800 200	1 537 486

*Does not include combustion turbine generators, but does include steam turbine-generators for nuclear power plants

Table 20/MANUFACTURE OF STEAM TURBINE-GENERATORS (4,000 kW and Larger)

Customer	Shipped	Scheduled as of January 1, 1984		Total Scheduled for Shipment as of 1 1 84	New Orders Booked 1983
	1983	1984	1985 and Later		
U S Electric Power Systems					
Units	13	13	78	91	4
kW	5 662 825	6 549 268	49 736 753	56 286 021	716 165
U S Industrials					
Units	6	18	11	29	21
kW	222 828	627 874	305 422	933 296	661 954
Exports from U S					
Units	15	8	8	16	1
kW	6 017 249	3 835 574	4 518 992	8 354 566	132 000
Total					
Units	34	39	97	136	26
kW	11 902 902	11 012 716	54 561 167	65 573 883	1 510 119

Table 20-A/MANUFACTURE OF CONVENTIONAL STEAM TURBINE-GENERATORS (4,000 kW and Larger) (Included in Table 20)

Customer	Shipped	Scheduled as of January 1, 1984		Total Scheduled for Shipment as of 1-1-84	New Orders Booked
	1983	1984	1985 and Later		1983
U.S. Electric Power Systems					
Units	13	12	73	85	4
kW	5,662,825	6,439,268	43,422,775	49,862,043	716,165
U.S. Industrials					
Units	6	18	11	29	21
kW	222,828	627,874	305,422	933,296	661,954
Exports from U.S.					
Units	12	8	5	13	1
kW	3,215,574	3,835,574	2,126,000	5,961,574	132,000
Total					
Units	31	38	89	127	26
kW	9,101,227	10,902,716	45,854,197	56,756,913	1,510,119
U.S. E.P.S. Orders to Foreign Manufacturers (Imports)					
Units	2	2	5	7	4
kW	1,292,000	637,000	1,751,000	2,388,000	186,000

Table 20-B/MANUFACTURE OF NUCLEAR STEAM TURBINE-GENERATORS (50,000 kWe and Larger) (Included in Table 20)

Customer	Shipped	Scheduled as of January 1, 1984		Total Scheduled for Shipment as of 1-1-84	New Orders Booked
	1983	1984	1985 and Later		1983
U.S. Electric Power Systems					
Units			6	6	
kW			6,423,978	6,423,978	
U.S. Industrials					
Units					
kW					
Exports from U.S.					
Units	3		3	3	
kW	2,801,675		2,392,992	2,392,992	
Total					
Units	3		9	9	
kW	2,801,675		8,816,970	8,816,970	
U.S. E.P.S. Orders to Foreign Manufacturers (Imports)					
Units					
kW					

Table 21/MANUFACTURE OF GENERATORS FOR HYDRAULIC TURBINES* (4,000 kW and Larger)

Customer	Shipped 1983	Scheduled as of January 1, 1984: 1984	Scheduled as of January 1, 1984: 1985 and Later	Total Scheduled for Shipment as of 1-1-84	New Orders Booked 1983
U.S. Electric Power Systems					
Units	5	7		7	2
kW	275,000	226,317		226,317	27,367
U.S. Industrials					
Units					
kW					
Exports from U.S.					
Units					
kW					
Total					
Units	5	7		7	2
kW	275,000	226,317		226,317	27,367
U.S.E.P.S. Orders to Foreign Manufacturers (Imports)					
Units	6	9	10	19	7
kW	124,896	743,250	2,242,100	2,985,350	842,000

*Includes generators for pumped storage plants

Table 22/MANUFACTURE OF CONVENTIONAL STEAM GENERATORS (450 Psi Pressure and Higher)

Customer	Shipped 1983	Scheduled as of January 1, 1984: 1984	Scheduled as of January 1, 1984: 1985 and Later	Total Scheduled for Shipment as of 1-1-84	New Orders Booked 1983
U.S. Electric Power Systems					
Units	10	8	24	32	1
M Lb/Hr	45,888	39,096	123,932	163,028	4,700
U.S. Industrials					
Units	4	2	–	2	2
M Lb/Hr	1,649	346	–	346	346
Exports from U.S.					
Units	5	1	3	4	
M Lb/Hr	17,121	4,579	12,075	16,654	
Total					
Units	19	11	27	38	3
M Lb/Hr	64,658	44,021	136,007	180,028	5,046

Table 23/MANUFACTURE OF HYDRAULIC TURBINES*
(5,000 Horsepower and Larger)

Customer	Shipped	Scheduled as of January 1, 1984		Total Scheduled for Shipment as of 1-1-84	New Orders Booked
	1983	1984	1985 and Later		1983
U.S. Electric Power Systems					
Units	5	10	7	17	
Hp	1,052,300	2,391,180	1,536,000	3,927,180	
U.S. Industrials					
Units					
Hp					
Exports from U.S.					
Units	3	4	1	5	
Hp	960,000	595,400	91,800	687,200	
Total					
Units	8	14	8	22	
Hp	2,012,300	2,986,580	1,627,800	4,614,380	
U.S.E.P.S. Orders to Foreign Manufacturers (Imports)					
Units					
Hp					

*Includes hydraulic turbines for pumped storage plants

Table 24/MANUFACTURE OF COMBUSTION TURBINE-GENERATORS
(4,000 kW and Larger)

Customer	Shipped	Scheduled as of January 1, 1984		Total Scheduled for Shipment as of 1-1-84	New Orders Booked
	1983	1984	1985 and Later		1983
U.S. Electric Power Systems					
Units	2		1	1	
kW	192,880		75,000	75,000	
U.S. Industrials					
Units	4	19		19	18
kW	194,940	1,414,540		1,414,540	1,338,740
Exports from U.S.					
Units	8	3		3	11
kW	354,500	187,500		187,500	542,000
Total					
Units	14	22	1	23	29
kW	742,320	1,602,040	75,000	1,677,040	1,880,740
U.S.E.P.S. Orders to Foreign Manufacturers (Imports)					
Units		1		1	1
kW		75,000		75,000	75,000

Table 25/MANUFACTURE OF NUCLEAR REACTORS (50,000 kWe and Larger)

Customer	Completed	Scheduled as of January 1, 1984		Total Scheduled for Completion as of 1-1-84	New Orders Booked
	1983	1984	1985 and Later		1983
U.S. Electric Power Systems					
Units	3	15	55	70	
kWe	3,040,000	16,852,000	61,672,000	78,524,000	
Exports from U.S.					
Units	2	9	20	29	
kWe	1,517,000	7,346,000	18,432,000	25,778,000	
Total					
Units	5	24	75	99	
kWe	4,557,000	24,198,000	80,104,000	104,302,000	

Table 26/MANUFACTURE OF POWER TRANSFORMERS (501 kVA and Larger)

Customer		Shipped 1983	Scheduled as of January 1, 1984: 1984	1985	1986	1987	1988	1989 and Later	Total Schedl. for Shipment as of 1-1-84	New Orders Booked 1983
501 to 10,000 kVA										
U.S. Electric Power Systems and U.S. Industrials	(Units	4,372	1,628	30	37	26	4	47	1,772	4,193
	(mVA	11,032	4,260	56	194	119	45	329	5,003	10,219
Exports from U.S.	(Units	319	87					8	95	186
	(mVA	828	214					76	290	486
TOTAL	(Units	4,691	1,715	30	37	26	4	55	1,867	4,379
	(mVA	11,860	4,474	56	194	119	45	405	5,293	10,705
10,001 to 30,000 kVA										
U.S. Electric Power Systems and U.S. Industrials	(Units	533	244	28	14			18	304	505
	(mVA	13,723	6,246	904	405			556	8,111	14,184
Exports from U.S.	(Units	10	3						3	24
	(mVA	454	106						106	751
TOTAL	(Units	543	247	28	14			18	307	529
	(mVA	14,177	6,352	904	405			556	8,217	14,935
30,001 to 100,000 kVA										
U.S. Electric Power Systems and U.S. Industrials	(Units	188	115	22	4	4		16	161	162
	(mVA	11,834	8,053	1,314	242	200		1,111	10,920	10,490
Exports from U.S.	(Units	4	2						2	
	(mVA	297	107						107	
TOTAL	(Units	192	117	22	4	4		16	163	162
	(mVA	12,131	8,160	1,314	242	200		1,111	11,027	10,490
100,000 kVA and Larger										
U.S. Electric Power Systems and U.S. Industrials	(Units	141	145	21	7	5	6	10	194	105
	(mVA	45,884	47,550	8,751	3,764	2,471	1,814	3,610	67,960	34,602
Exports from U.S.	(Units	8	1		2				3	
	(mVA	3,464	217		434				651	
TOTAL	(Units	149	146	21	9	5	6	10	197	105
	(mVA	49,348	47,767	8,751	4,198	2,471	1,814	3,610	68,611	34,602
Total (501 kVA and Larger)										
U.S. Electric Power Systems and U.S. Industrials	(Units	5,234	2,132	101	62	35	10	91	2,431	4,965
	(mVA	82,473	66,109	11,025	4,605	2,790	1,859	5,606	91,994	69,495
Exports from U.S.	(Units	341	93		2			8	103	210
	(mVA	5,043	644		434			76	1,154	1,237
TOTAL	(Units	5,575	2,225	101	64	35	10	99	2,534	5,175
	(mVA	87,516	66,753	11,025	5,039	2,790	1,859	5,682	93,148	70,732

1983 ELECTRIC POWER ANNUAL REPORT

Replaces and combines the features of what would have been the 1983 Year-End and the 1984 Annual Electric Power Surveys. This report presents information concerning the electric power supply, expansion of electric generating facilities, and the manufacture of heavy electric power equipment in the United States as of the end of 1983.

Power supply data including peak loads, capability to meet loads, megawatthour requirements, load factors, and comparison between summer and winter seasons is shown on a total industry basis for each of the nine reliability councils and for total contiguous U.S.

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STATISTICS ON FUEL USED TO GENERATE ELECTRICITY BY THE ELECTRIC UTILITY INDUSTRY.

Fuel data are presented for the United States by state and Census Division, detailed by type of fuel (coal, oil, natural gas and nuclear) for both the Total Electric Utility Industry and the Investor-Owned segment. Units consumed, fuel cost in cents per kilowatthour, generation, heat rate and average Btu content are shown for the most recent and four preceding years. Published annually in late summer.

CATALOGUE OF INVESTOR-OWNED ELECTRIC UTILITY COMPANIES OPERATING IN THE UNITED STATES.

Complete reference guide to the names and addresses of investor-owned companies, arranged by state according to location of principal office. Holding companies and systems and jointly-owned companies are cross-referenced with operating subsidiaries. An additional listing ranks companies according to number of ultimate customers. Published annually in the winter. 50 p.

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Provides a method of calculating approximately 100 ratios used by the utility industry in analyzing financial reports. Categories of ratios include Earnings and Return; Common Dividend; Coverages; Interest and Preferred Dividend; Balance Sheet; Revenue and Sales; Expense; Tax; Plant; Depreciation; and other ratios, such as funds used during construction as percent of earnings and per share, capital expenditures, etc. Prepared by EEI Financial Ratios Subcommittee of the Statistical Committee 28 p.

EEI POCKETBOOK OF ELECTRIC UTILITY INDUSTRY STATISTICS.

A pocket-sized quick reference of national electric industry data, some dating from 1902 to the present. Categories include data on installed capacity and generation; capital and finance; sales, revenue and customers; fuels; private and public ownership. Published annually in late fall. 37 p.

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The reel of magnetic tape (standard label, 6250 BPI, EBCDIC) contains 72 files corresponding to all of the tables printed in the hard-copy version of the Statistical Yearbook. Each file is identified by a data set name in the form TABLEnn. Documentation is provided showing positional layouts of the data elements in each file. The incorporation of this tape into a data base will facilitate the retrieval and manipulation of series dealing with most aspects of the electric utility industry.

POST-SUMMER ELECTRIC POWER SURVEY

Reports results of a generating equipment survey as of July 1, and a summer peak load survey as of September 15. Contains first actual regional capability, peak load, and percent capacity margin values for the summer season just completed. Also includes information on the manufacture of heavy electric power equipment in the U.S. and foreign-made equipment to be imported by U.S. electric power systems; orders and shipments during the first half of the year and backlogs as of July 1. Scheduled generating additions by region are individually identified in an appendix. A feature transferred from the discontinued Annual Electric Power Surveys is a collection of tables showing the electric utility industry's ten-year projected fuel use. This data is extracted from NERC's spring compilation of projections of fuel use in physical units and the megawatthours to be generated in each region by fuel or other sources of energy. Published near the end of each year. 40 p.

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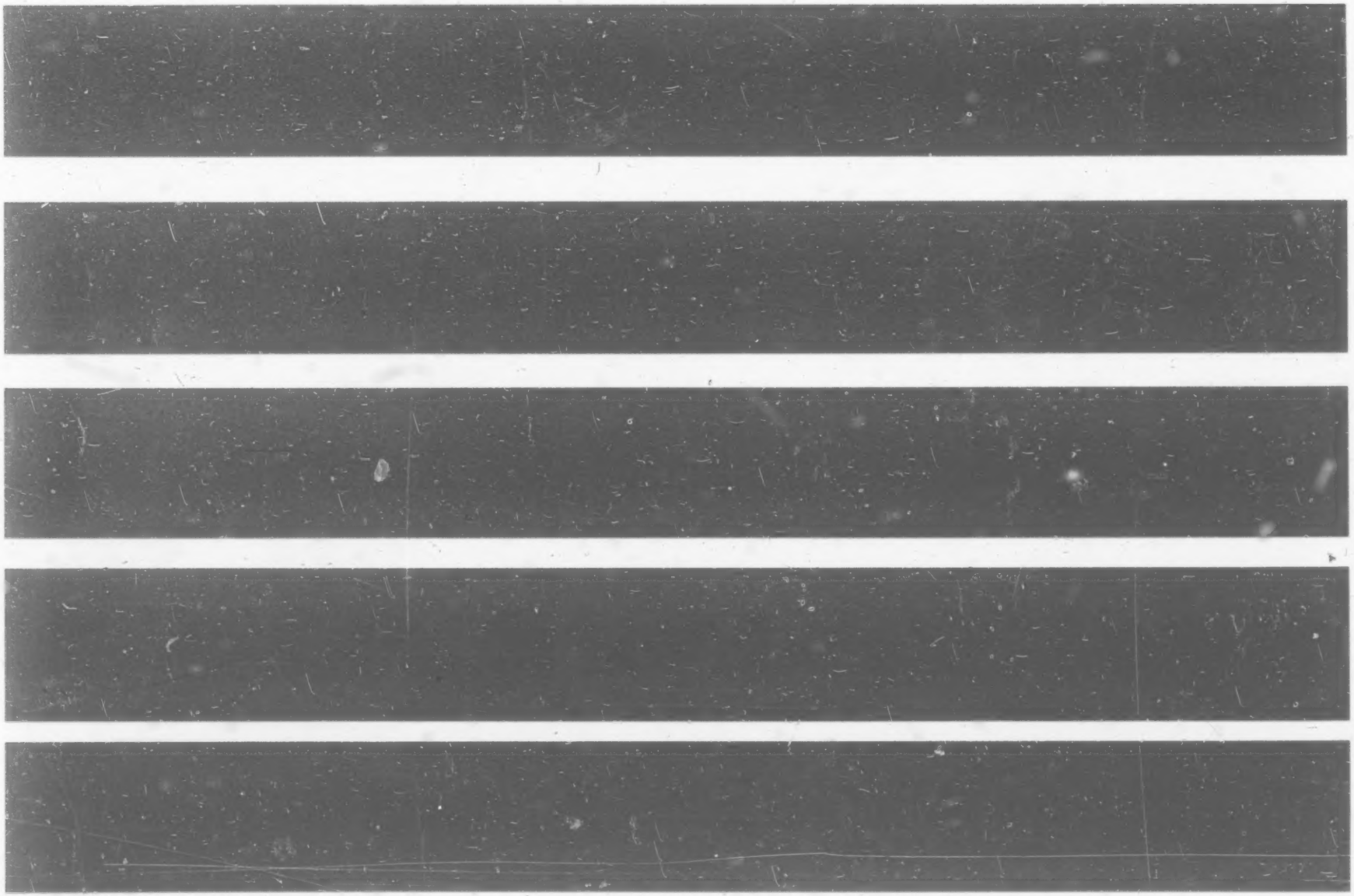

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